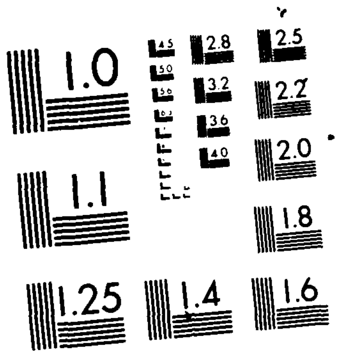
AD-A173 690 FEASIBILITY STUDY OF COAL GASIFICATION/FUEL CELL/COGENERATION PROJECT FOR..(U) EBASCO SERVICES INC NEW YORK B ROSSI ET AL. JUL 85 DAAG29-85-C-0007 1/3

UNCLASSIFIED F/G 10/2 NL



MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

AD-A173 690

FEASIBILITY STUDY OF

COAL GASIFICATION / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE

PROJECT DESCRIPTION

REPORT CLIN 000303

PREPARED FOR

DEPARTMENT OF THE ARMY

AND

GEORGETOWN UNIVERSITY

JULY, 1985

EBASCO

EBASCO SERVICES INCORPORATED

Two World Trade Center

New York, N.Y. 10048

FEASIBILITY STUDY OF

COAL GASIFICATION / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE

PROJECT DESCRIPTION

REPORT CLIN 000303

PREPARED FOR

DEPARTMENT OF THE ARMY
AND
GEORGETOWN UNIVERSITY

JULY, 1985

DTIC
ELECTE
OCT 3 0 1986
S D
A

EBASCO

EBASCO SERVICES INCORPORATED

Two World Trade Center

New York N Y 10048

Unclassified

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE

READ INSTRUCTIONS BEFORE COMPLETING FORM

1. REPORT NUMBER CLIN 000303	2. GOVT ACCESSION NO. AD-A173690
3. RECIPIENT'S CATALOG NUMBER	
4. TITLE (and Subtitle) FEASIBILITY STUDY OF COAL GASIFICATION/FUEL CELL/ COGENERATION, FORT HOOD, TEXAS SITE PROJECT DESCRIPTION	5. TYPE OF REPORT & PERIOD COVERED Site Specific Project Description - Draft
	6. PERFORMING ORG. REPORT NUMBER
7. AUTHOR(s) B Rossi, P Estreich	8. CONTRACT OR GRANT NUMBER(s) DAAG 29-85-C-0007
9. PERFORMING ORGANIZATION NAME AND ADDRESS Ebasco Services Inc 2 World Trade Center New York, New York 10048	10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS 611102-BH57-09
11. CONTROLLING OFFICE NAME AND ADDRESS Procurement Office U S Army Research Office P O Box 12211 Research Triangle Park N C 27709-2211	12. REPORT DATE July, 1985
	13. NUMBER OF PAGES 185
14. MONITORING AGENCY NAME & ADDRESS (if different from Controlling Office)	15. SECURITY CLASS. (of this report) Unclassified
	15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT (of this Report)

Approved for public release: distribution unlimited

17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)

18. SUPPLEMENTARY NOTES

Prepared in cooperation with Georgetown University. The views, opinions and/or findings contained in this report are those of the author(s) and should not be construed as an official Department of the Army position, policy or decision, unless so designated by other documentation.

19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

Fuel Cell/Coal Gasification/Cogeneration/Exemplar Study

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

Report describes a Coal Gasification/Fuel Cell/Cogeneration (GFC) project that is specific to the Fort Hood, Texas site.

DD FORM 1 JAN 73 1473 EDITION OF 1 NOV 65 IS OBSOLETE

Unclassified

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

FORT HOOD, TEXAS

TABLE OF CONTENTS

A-1

QUALITY INSPECTED 4

7774A

TABLE OF CONTENTS (Cont'd)

TABLE OF CONTENTS (Cont'd)

TABLE OF CONTENTS (Cont'd)

LIST OF FIGURES

LIST OF TABLES

LIST OF TABLES (Cont'd)

1.0 INTRODUCTION

The purpose of this report is to describe a Coal Gasification/Fuel Cell/Cogeneration (GFC) project that is specific to the Fort Hood, Texas site.

The project at this site, as with those at the three other sites selected for this program, is intended to demonstrate the technical, economic and financing viability of power generation by fuel cells using gas from coal.

The specific design described in this report is based on a United Technology Corporation nominal 11 MW fuel cell and has evolved from the following two predecessor reports:

1. CLIN 0001 - Basic System Description, March 1985
2. CLIN 000203 - Preliminary Site Survey

Although this report does not include cost estimates or economic and financial analyses, it is intended to form the basis for such information which will be included in forthcoming reports numbered CLIN 0004, CLIN 0005 and CLIN 0006.

Mass and energy balances have been prepared for the gasification, gas processing, fuel cell and thermal management systems using a Texas lignite as the design coal.

With safety, aesthetic and land use criteria satisfied, this plant will meet federal and local environmental laws and regulations, should have a design/fabrication/construction period of approximately 44 months and have performance characteristics as shown in Table 2-2.

1.1 Overview

Section 2.0 of this report discusses design criteria, overall plant description, plant performance, plant availability and required staffing. It then addresses a project schedule that accounts for requirements additional to the basic GFC plant that integrate the total installation with the existing site's physical plant and unique energy needs. These additional requirements are referred to as the "GFC Site Specific Increment" and are described in this section.

Section 3.0 discusses the physical arrangement of the plant as well as the electrical and other utility connections.

Section 4.0 discusses present and future electrical loads and Section 5.0 covers the same for thermal loads.

Section 6.0 entitled, System Design Description, discusses for each of the major systems constituting the GFC, functions and design requirements, system description, system performance, maintenance requirements and technical risks.

Section 7.0 discusses environmental regulations and permitting requirements comparing GFC emissions with regulatory limits.

The following summarizes some of the information described in this report.

I. GENERAL

- Plant floor area is approximately 90,000 ft^2;
- Plant is designed around an 11 MW UTC Fuel Cell;
- The Thermal Management System (TMS) is arranged to maximize electrical power production;
- Plant will meet PURPA criteria for recognition as a "Qualifying Facility" (QF).
- GFC emissions will be well below regulatory limits;

- System interfaces: Any electrical connections of power output to the Texas Power & Light Company (TP&L) grid will follow industry guidelines and include any additional TP&L requirements.

II. SYSTEM DESIGN DESCRIPTION

A. Material Handling

1. Coal
   - The function of this system is to receive, weigh, sample, screen, store, convey lignite to the gasifiers.

2. Ash
   - The function is to remove ash collected in gasifier storage hoppers

   The material handling system requiring only basic maintenance has high reliability and low technical risk.

B. Coal Gasification

- The function of this system is to derive gas from coal for ultimate use by the fuel cell;
- Performance of the Wellman-Galusha gasifier indicates that it can operate from 8.5% to 111% of its rated capacity of 4 tons/hr;
- Maintenance is minimal, most of it being performed during the scheduled two week annual shutdown;

- As a system with a long history of successful industrial application, technical risks are minimal.

C. Gas Processing

- The function of this section is to cool, clean, and compress the gasifier effluent, and then to convert it to a hydrogen-rich, sulfur-free stream, suitable for use by the fuel cell;
- The performance of this section is assessed as satisfactory under full and part load conditions, with variations in flow rate not adversely affecting the gas quality;
- Equipment for this process is selected for maximum reliability and minimum maintenance. Major maintenance is performed during the scheduled annual shutdown;
- Technical risks are assessed as low.

D. Fuel Cell and Power Conditioner

1. Fuel Cell

- The function of the fuel cell is to convert hydrogen in the gas from the Gas Processing Section into usable electrical, mechanical, and thermal energy;

- The fuel cell operates at about 10% greater efficiency at 50% load than at 100% load. Voltage degrades a little more than 10% over the 40,000 hour life of the cell stacks;

- Maintenance for the expander, compressor and generator is typical of that for rotating equipment. Fuel cell stacks are periodically replaced to maintain minimum voltage level;

- Technical risks include the potential for electrolyte leakage, low cell voltage, catalyst poisoning or coolant fouling. However these problems can be averted through design changes or proper maintenance.

2. Power Conditioner

- The function of the power conditioner is to convert the dc output of the fuel cell to 3 phase ac power for connection to the TP&L grid. It also regulates the operation of the fuel cell so as to maintain the required power output;

- The performance of the power conditioner is rated at efficiencies of 90% over the entire operating load range;

- Systems utilizing similar design concepts (e.g. Tokyo Electric Power Co. (TEPCO) 4.5 MW cell) have proven to be reliable in utility related applications.

E. Thermal Management System (TMS)

- The TMS converts thermal and chemical energy flows discharged from the fuel cell into one or more of following energy forms that can reduce plant operating costs or generate revenue.

  1) Steam and electrical power to satisfy GFC system process demands;
  2) Steam to provide heating and cooling for the Medical Complex and future Third Corps Headquarters Building.
  3) Electrical power for export to TP&L or direct consumption by Fort Hood.

- Since the fuel cell efficiency increases as the load decreases, steam production tends to drop more rapidly that does fuel cell power output with a lowering of load.

Maintenance: Equipment for the TMS is of proven reliability which can be sustained through regular maintenance.

Technical risk is minimal, being no more than that normally assumed by commercial ventures in mature technologies.

F. Auxiliary Systems

- The auxiliary systems include 1) Electrical for powering auxiliary systems; 2) Water cooling system to dispose of heat from coal gasifiers, gas processing, and the TMS system; and 3) Water treatment to take out impurities in the water incompatible with any step of the process.

- Instrumentation and control system is configured with centalized control and control processors. Each major state of the GFC process has a local subsystem control board located close to the process area.

III. ENVIRONMENTAL

- This section reviews emissions discusses the applicable environmental laws and regulations and concludes that the GFC system requires no extraordinary emission control measures.

IV. GFC Site Specific Increment

The "GFC Site Specific Increment" assures that the site receiving the fuel cell system has its unique energy requirements fulfilled with no net loss of prior essential assets or facilities.

At Fort Hood the GFC Site Specific Increment includes the following:

1. A central plant to provide cooling and heating for the Medical Complex and the future Third Corps Headquarters Building.

2. An underground piping system to distribute chilled water and medium temperature hot water from the Central Cooling and Heating Plant (CCHP) to the end users. This includes any required cathodic protection or other corrosion control measures.

3. Connections to the end user heating and cooling systems, including heat exchangers, controls and modifications to existing systems.

4. Required relocations of utilities that now serve the existing site.

Refer to paragraphs 2.2 and 6.5.6 for a description of the Central Cooling and Heating Plant.

2.0 SUMMARY

2.1 Design Criteria

Criteria and design objectives that govern the design and selection of systems, equipment and supporting facilities for the GFC plant are as follows:

1. Plant Availability and Reliability

   a) Maximum plant availability is to be achieved through use where possible, of commercially proven equipment.

   b) Redundancy is to be provided for critical controls and for selected motorized equipment.

   c) Natural gas is considered as a backup fuel. The economics of adding the gas service, methane reformer, hydrodesulfurizer, gas compressor and accessories will be reviewed in forthcoming report, CLIN 0004.

   d) Coal storage is to provide a minimum of 90 days GFC operation at plant maximum continuous rating.

2. Plant is designed around the UTC 11 MW nominal output fuel cell.

3. Plant is to operate baseloaded with the Thermal Management System designed to maximize steam production for use in a Central Cooling and Heating Plant rather than electrical power generation.

4. System operation is to be based on maximum automation and centralized control.

5. Plant is to be capable of meeting federal and local environmental requirements.

6. Most plant components are to be factory fabricated and pressembled for truck delivery.

7. Access roads for coal delivery, ash removal and for other vehicles serving the facility, must not interfere with normal traffic flow.

8. Safety criteria and regulations must be complied with, including those governing hydrogen, carbon monoxide and sulfuric acid.

9. Plant must provide suitable access for fire department vehicles and personnel.

10. Plant must meet Public Utilities Regulatory Policies Act (PURPA) criteria to be classified as a "Qualifying Facility" (QF).

11. Plant site conditions are as summarized in Table 2-1.

TABLE 2-1

SITE CONDITIONS[1]

Elevation Above Mean Sea Level, ft	1015
Design Atmospheric Pressure, psia	14.44
Summer Outdoor Design Temperatures, °F[2]	
(Dry Bulb)/(Mean Coincident Wet Bulb)	99/73
Winter Outdoor Design Dry Bulb, °F[3]	20
Summer Outdoor Design Wet Bulb, °F[4]	77
Summer Indoor[6] Design Dry Bulb, °F	105
Winter Indoor[6] Design Dry Bulb, °F	55
Annual Heating Degree Days, Average[5]	1959

Notes:

1. Technical Manual TM-5-758, Engineering Weather Data, July 1, 1978, Department of the Army, p. 1-31, Data for Fort Hood/Robert Gray AAF.

2. Dry bulb equaled or exceeded 1% of time on the average during the warmest four consecutive months.

3. Dry bulb equaled exceeded 99% of time on the average for the coldest three months.

4. Used for cooling tower design: Wet bulb exceeded 1% of time on the average during the warmest four consecutive months.

5. 30 year average for 65°F base.

6. Unairconditioned spaces.

2.2 Overall Plant Description

Layouts indicate that approximately 90,000 ft^2 of floor area is required for the GFC system. (Refer to paragraph 3.1). The tallest structures are the Wellman-Galusha gasifier and the saturator (T-201). Including the feed conveyor, the gasifier is 80'-0" above the base slab at 70' elevation. The saturator (T-201) in the Gas Cooling Section is 70' high.

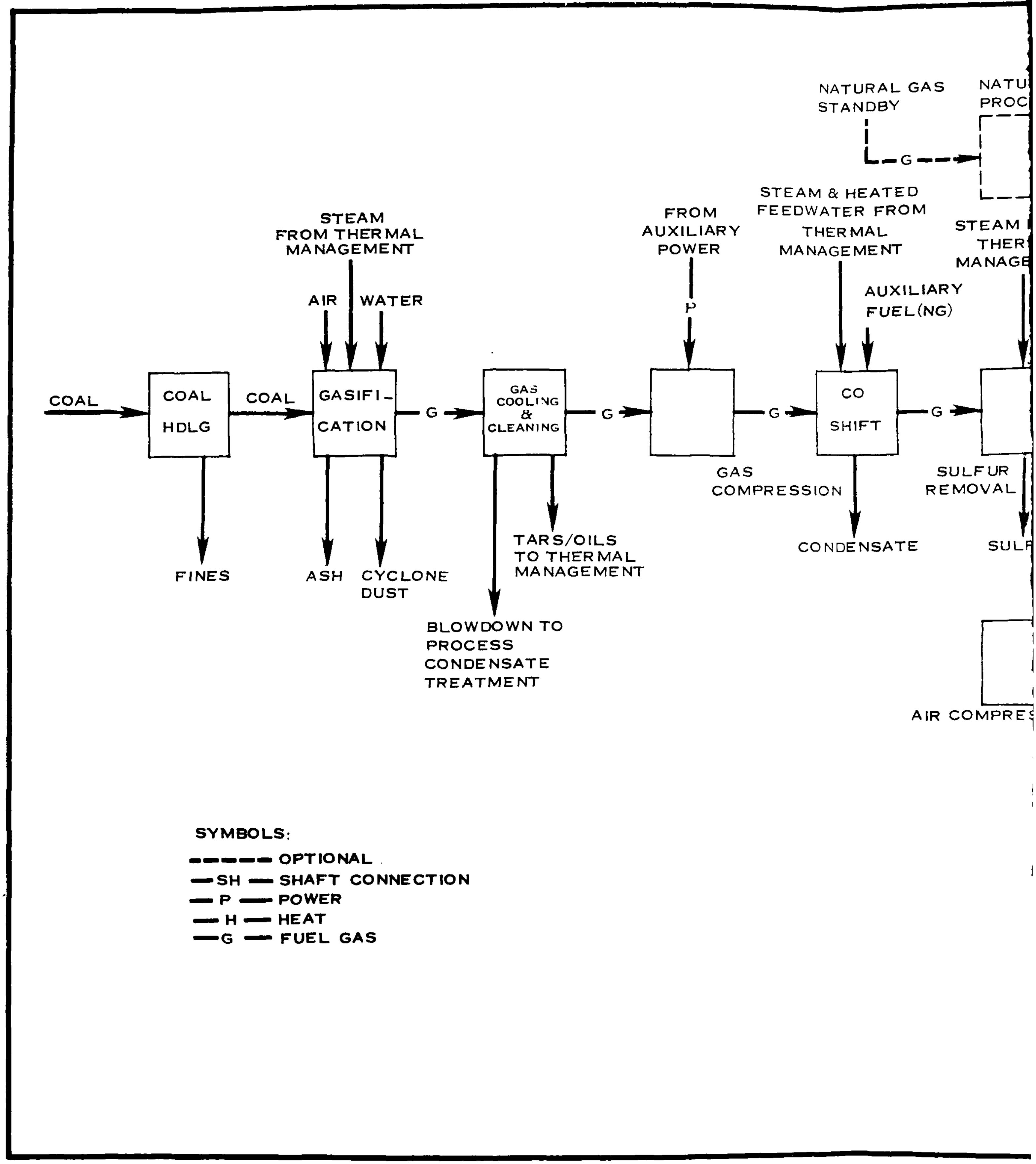
This system is based on the UTC fuel cell and has a nominal gross electrical output of 11.6 MW.

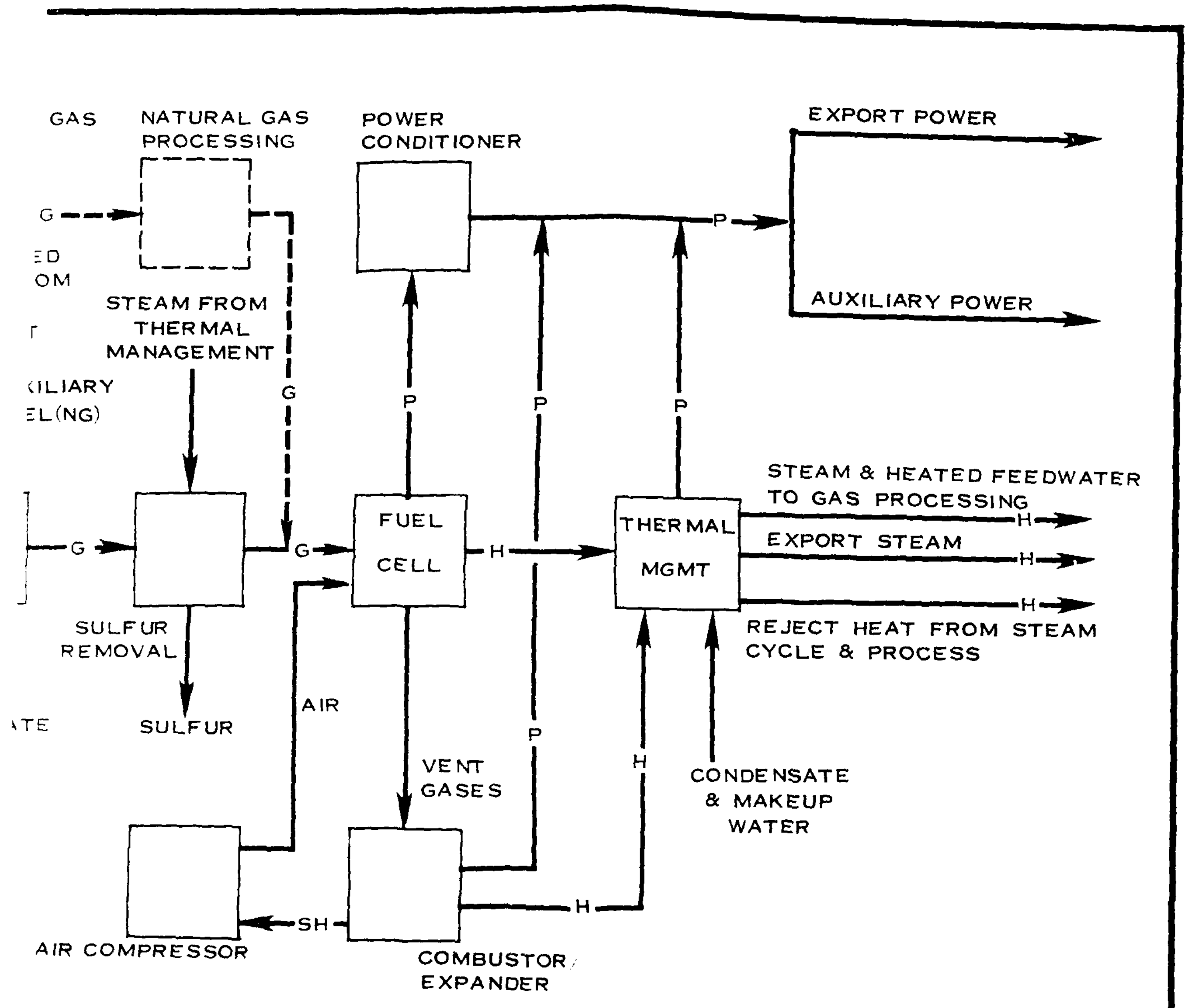
A conceptual view of the base system design is given by the block flow diagram of Figure 2-1. The process starts with truck delivery of lignite to a live storage silo located adjacent to the 90 day open storage pile. Lignite reclaimed from this silo is screened and then conveyed to the three Wellman-Galusha gasifiers. Saturated gasification air and steam reacts with the coal in the gasifier, producing hot raw gas and ash. The raw gas is cooled to condense and separate out oils and tars and then compressed to 167 psia.

The design for the Fort Hood site includes motor driven centrifugal gas compressors which are electrically powered from GFC system output.

Utilizing steam at 175 psia from the CO shift boiler and from the Thermal Management System, the compressed gas undergoes a CO shift reaction to increase the hydrogen content. The gas is then desulfurized and heated before final polishing and feeding to the fuel cell.

Receiving compressed fuel gas and air at the anode and cathode respectively, the fuel cell electrochemically converts the energy in the hydrogen and oxygen components of these feed gases to direct current power and heat. The fuel cell power output is then conditioned for use in an AC utility network.


NATURAL GAS
STANDBY
NATU
PROC
G
STEAM & HEATED
FEEDWATER FROM
THERMAL
MANAGEMENT
STEAM
FROM THERMAL
MANAGEMENT
FROM
AUXILIARY
POWER
STEAM
THER
MANAGE
AIR
WATER
P
AUXILIARY
FUEL (NG)
COAL
COAL
HDLG
COAL
GASIFI-
CATION
G
GAS
COOLING
&
CLEANING
G
G
CO
SHIFT
G
GAS
COMPRESSION
SULFUR
REMOVAL
FINES
ASH
CYCLONE
DUST
TARS/OILS
TO THERMAL
MANAGEMENT
CONDENSATE
SULF
BLOWDOWN TO
PROCESS
CONDENSATE
TREATMENT
AIR COMPRES
SYMBOLS:
OPTIONAL
SH SHAFT CONNECTION
P POWER
H HEAT
G FUEL GAS



DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE
BLOCK FLOW DIAGRAM

FIGURE 2-1

EBASCO SERVICES INCORPORATED

Vent gases from the fuel cell power a combustor/expander which drives the air compressor and a 2300 kW induction motor-generator. This latter equipment is part of the Thermal Management System which receives and "manages" heat from the fuel cell electrochemical reaction, from the combustor/expander and from any process heat source. Byproduct tars and oils are fired in a supplementary burner section located at the entrance to the heat recovery steam generator.

The design of the Thermal Management System largely determines the magnitude and relative proportions of plant power output and export heat.

An average of 41,300 lb/hr of cogenerated steam at 230 psia is available from the Thermal management System when the GFC is operating at rated conditions. Of this amount, 20,300 lb/br is supplied to the Central Cooling and Heating Plant which furnishes chilled water at 42^{o}F and medium temperature hot water at approximately 320^{o}F to the Medical Complex and to the future Third Corps Headquarters Building.

The remainder of steam from the TMS, is fed to a condensing turbine and synchronous generator having an average output of 1700kW.

Also included in the Thermal Management System is a cooling tower and circulating water system that removes approximately 58 x 10^6 Btu/hr of heat rejected from the gas process, from compressor intercoolers and from steam condensers serving the power turbine.

Other systems required to support the facility include fire detection and protection, instrumentation and controls, makeup water treatment, drainage, heating and ventilation of enclosures, freeze protection of equipment and piping, flush water and compressed air and nitrogen for blanketing and purging.

2.3 Plant Performance

GFC plant performance is summarized in Table 2-2. The plant has an overall efficiency of 36% and a heat rate of 12,640 Btu/kWh.

The Public Utilities Regulatory Policies Act (PURPA) which is administered by the Federal Energy Regulatory Commission (FERC), governs how a cogeneration facility can become a Qualifying Facility (QF).

An important advantage of this QF status is that it provides the option to the plant operator to sell all or a fraction of electric power produced by the GFC to the public utility at avoided costs.

The operating standard of PURPA requires that a new QF must produce at least 5% of the total energy output as useful thermal energy. The facility heat balance in Section 6.5 satisfies this requirement with a thermal energy percentage of 34.9

The second standard imposes criteria for minimun operating efficiencies on facilities where oil or gas is the primary fuel and is therefore not applicable to this system.

The remaining requirement states that a utility may not own more than 50% of a cogeneration facility and is also inapplicable.

TABLE 2-2

SYSTEM PERFORMANCE

(UTC CELL, FORT HOOD,TX)

Coal Input to Gasifier(1)(4), Tons/Day	286.3
Heating Value of Coal Input(2), Btu/hr	160.3×10^6
Fuel Cell Output, MW DC	11.6
Power Conditioner Output, MW AC	11.0
Power from Gas Expander, MW	2.34
Power from Steam Turbine, MW	1.28
Auxiliary Power, MW	3.55
Net Power, MW	11.1
Export Steam @230 psia, lb/hr	20,300
Tar and Oils Heat Content, Btu/hr	25.6×10^6
Heat Rate, Btu/KWh(3)	12,640
Overall Plant Efficiency, %	36.2

Notes:

1. Based on maximum of 15% fines in as-received coal.
2. Based on higher heating value of 6718 Btu/lb
3. Takes credit for thermal value of export steam.
4. Communication with representatives of North American Coal Co. in Malakoff, Texas indicates that coal will be available from this source without impinging on contracted supplies for Houston, Lighting and Power Co.

Based on the above, the performance of the GFC system at Georgetown meets the criteria for classification as a "Qualifying Facility."

The overall energy balance is shown in Table 2-3.

Based on the ability of the gasifier to accept up to 15 percent as fines, all fines are assumed to be usefully consumed.

Of the total system energy loss of 101 x 10^6 Btu/hr, 63 percent occurs in the coal handling, coal gasification and gas processing sections of the GFC system.

Therefore, in the final design of this system, major efforts must be directed to reducing these losses in order to maximize cycle efficiency.

TABLE 2-3

OVERALL ENERGY BALANCE

Item		Energy (10^6 Btu/hr) In	Energy (10^6 Btu/hr) Out
Energy in Coal		160.30	
Energy Produced (Gross)			49.24
Fuel Cells	37.54		
Gas Expander Generator	7.95		
Steam Turbine Generator	3.75		
Parasitic Power			(12.00)
Export Steam			21.40
Ash and Coal Dust			4.12
Heat Rejected by Cooling Tower			51.00
Other Heat Releases to Environment			46.54
CO Shift Air Cooler	13.4		
HRSG Stack Loss	25.1		
Miscellaneous	8.04		
TOTAL		160.30	160.30

2.4 Plant Availability

Systems and equipment are to be selected and arranged to provide maximum overall availability and reliability.

Availability for one year operation is defined as

$$A = 1 - \frac{US + PS}{365}$$

and reliability as

$$R = 1 - \frac{US}{365 - PS}$$

where US = Unscheduled Shutdown, days/yr

PS = Planned Shutdown, days/yr

Estimates of the days per year of unscheduled shutdown were developed for the component sections of the GFC and listed in Table 2-4. The fuel cell, power conditioner and Thermal Management System estimate of 22 days unscheduled shutdown per year is based on Reference 2-1. (Within this system group, the power conditioner has a reliability of 98.2 percent which represents 6 days unplanned outage).

In the Gas Cooling and Cleaning Section, the component with most potential for shutdowns was identified as the electrostatic precipitator. Experience with this item indicates a reliability of 99 percent or an unplanned outage of four days.

It may be noted that the Gasification, and Gas Processing Sections contribute an additional 17 days of unplanned shutdown, reducing the plant availability factor from 0.90 for a natural gas fueled plant to 0.85 for a coal gas fueled plant.

Operating as a base loaded plant at an average of 95 percent of maximum continuous rating, the plant capacity factor is 0.81 (= 0.95 x 0.85).

The above estimates apply to a GFC plant only after a sufficient period of "running in" and testing has occurred to eliminate initial operating and design problems. It is estimated that this period could be a year in duration.

TABLE 2-4

PLANT AVAILABILITY

Unscheduled Shutdown(1)		Days/Yr
Fuel Cell, Power Conditioner, Thermal Management System(2)		22
Gasifier		3
Electrostatic Precipitator		4
CO Shift		1
Stretford Desulfurizer		3
Gas Compressors		3
Material Handling(3)		3
Subtotal		39
Scheduled Shutdown		14
Total Annual Shutdown		53
Plant Reliability	(1 - 39/(365-14))	0.89
Plant Availability	(1 - (39 + 14)/365)	0.85
Plant Load Factor		0.95
Plant Capacity Factor	(0.85 x 0.95)	0.81

Notes:

1. Refers to complete GFC system shutdown caused by listed item.
2. See Reference 2-1
3. See Reference 2-2

2.5 Plant Staffing

An estimate of operator assignments to the various sections of the GFC plant for each of the three working shifts, is given in Table 2-5.

With each letter (A, B, C, etc.) representing one individual, five operators would be on duty at all times.

In addition to the five operators would be a supervisor located in the Control Room.

Considering days off, relief fill in, vacations, training, performance of maintenance tasks and premium payments for weekends and night shifts, a factor of 4.2 is applied to obtain "equivalent operating staff".

The total assigned to the plant is then as follows:

Equivalent Operating Staff (6x4.2)	25
Laboratory Technicians	3
Maintenance/Repair Personnel	3
Plant Manager/Engineer	1
Clerical	2
Total Equivalent Staff	34

TABLE 2-5

PLANT OPERATOR ASSIGNMENTS[1]

	Operator[2]
Material Handling	A
Gasification	A
Gas Cleaning, Cooling, Compression	B
CO Shift	B
Sulfur Removal & Recovery	B
Process Condensate Treatement	C
Water Treatment	C
Fuel Cell	D
Power Conditioner	D
Thermal Management System	D
Instrumentation and Control Systems	E
Auxiliary System	E

Total Operators = (A+B+C+D+E) =	5
Supervisor	1
Total Operating Staff	6

Notes:

1. Assignments are for a single shift.
2. Each letter (A, B, C, etc.) represents one plant operator.

2.6 Project Schedule

The 44-month project schedule shown in Figure 2-2 assumes that compliance with the National Environmental Policy Act (NEPA) will entail the preparation and review of an Environmental Assessment (EA) and not an Environmental Impact Statement (EIS). (If an EIS is required, the NEPA process could take an additional six months or longer.)

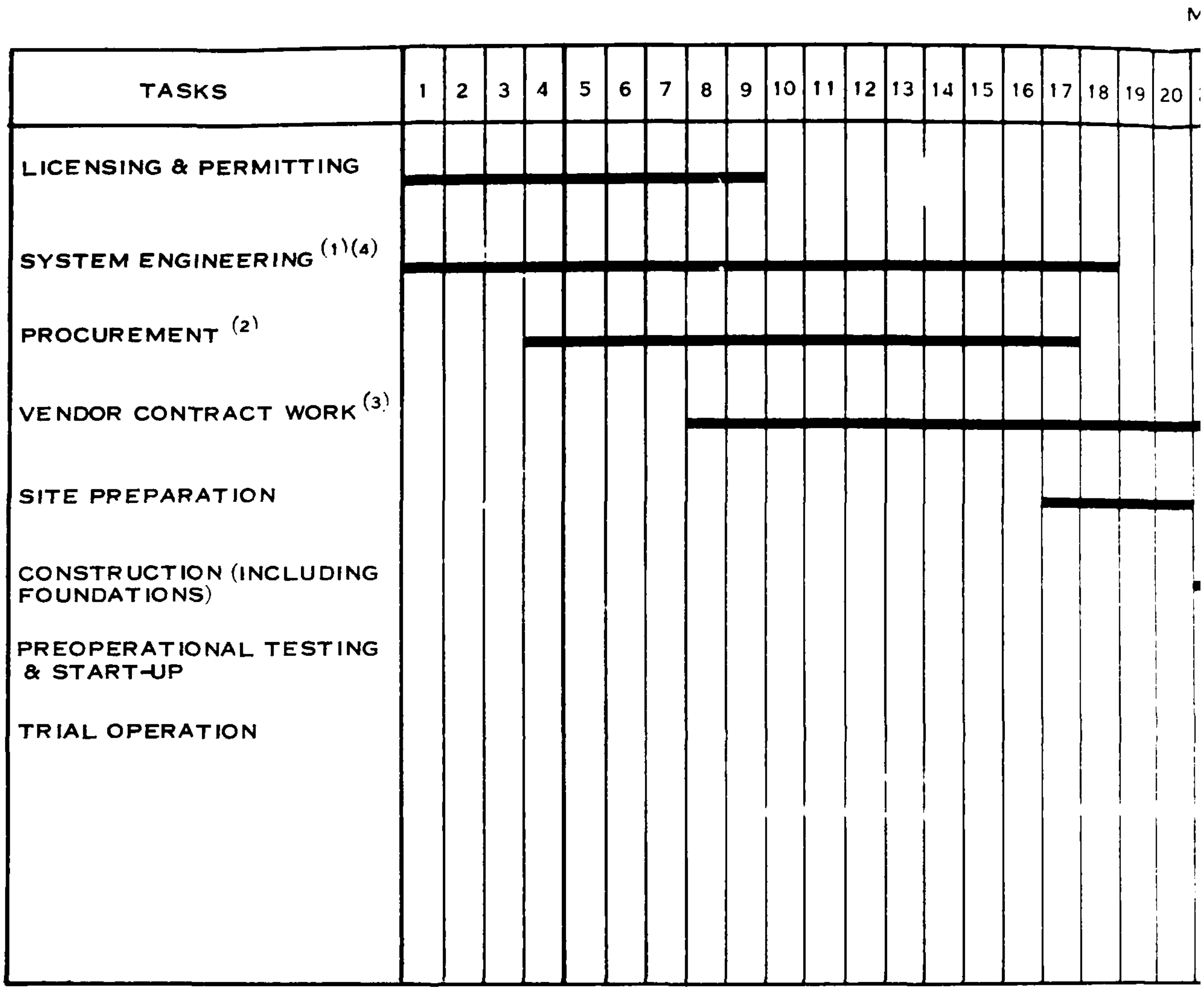
It also assumes that the federal and Texas approvals and permits will be available seven months after project start. This in turn allows letting contracts for supply of the longest lead items.

Work on GFC system foundations and structures would commence on the 21st month with installation of delivered equipment and interconnecting services completed in the 40th month.

It is estimated that site delivery would occur roughly 24 months after placement of an order in 1986 or 1987 - depending also upon prior production commitments. This makes the fuel cell/power conditioner package the project's longest lead item.

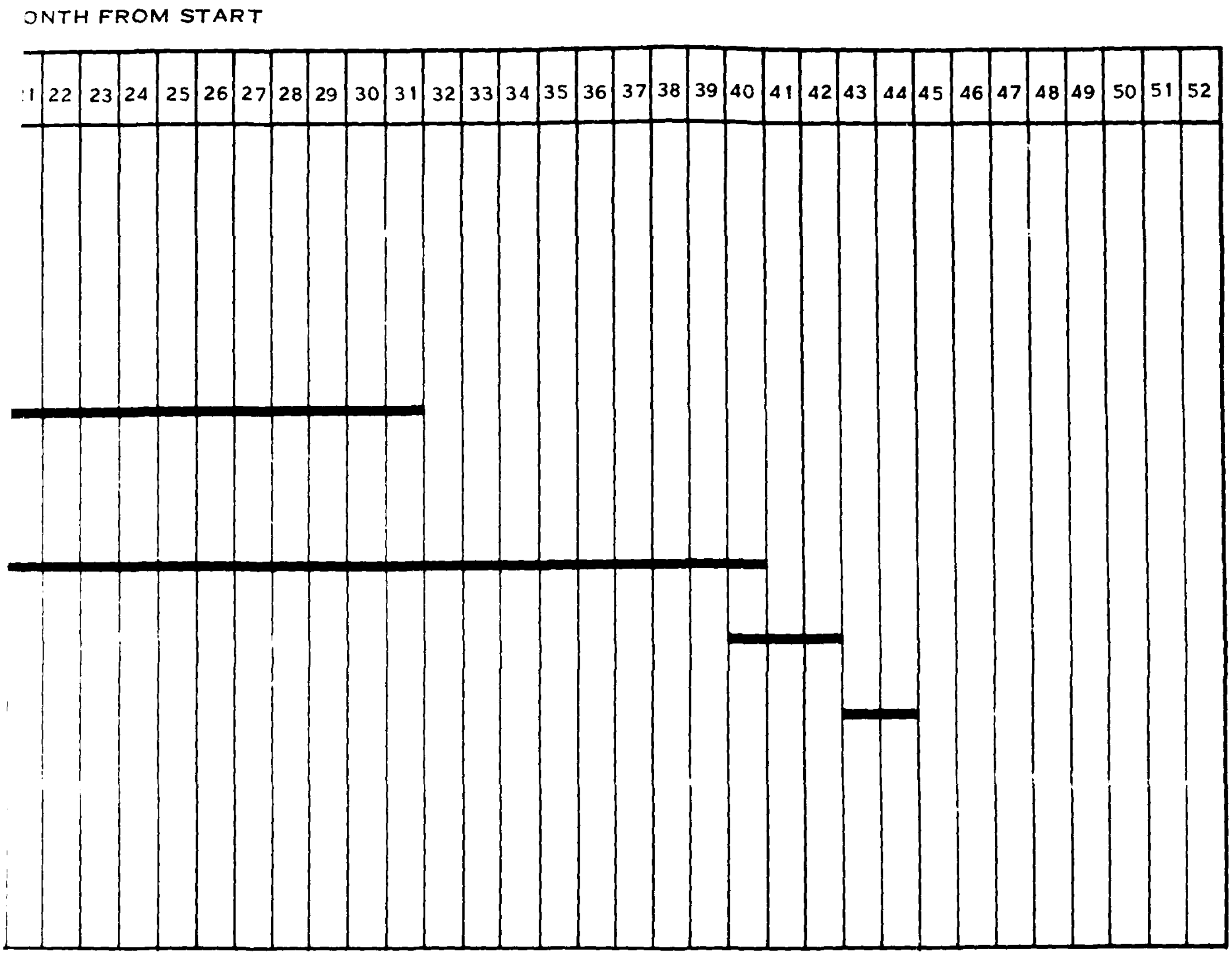
It therefore becomes necessary to initiate negotiations and place an order for the fuel cells as early in the project as possible. It is estimated that this order or letter of intent can be issued about seven months after start of GFC engineering (11 months after project start) with delivery of the fuel cells occurring in the 35th month. Some typical "order to delivery" time frame estimates by other suppliers are:

Steam turbine-generator	-	40 weeks
Gas expander - compressor	-	54 weeks
Vessels and towers	-	45 weeks
Gasifiers	-	26 weeks
Absorption chillers	-	20 weeks



NOTES:

1. INCLUDES DEVELOPMENT OF SYSTEM DESIGN DRAWINGS, SPECIFICATIONS. BID ANALYSES, REVIEW OF VENDOR SUBMITTALS
2. INCLUDES PROCUREMENT ACTIVITIES UP TO CONTRACT AWARDS
3. INCLUDES VENDOR ENGINEERING, FABRICATION & DELIVERY
4. THE START OF ENGINEERING FOLLOWS A 9 TO 12 MONTH PERIOD FOR PRELIMINARY ENGINEERING AND COAL SAMPLE TESTING.



DOA / GEORGETOWN UNIVERSITY

COAL GAS/FUEL CELL/COGENERATION

FORT HOOD, TEXAS SITE

PROJECT SCHEDULE

FIGURE 2-2

EBASCO SERVICES INCORPORATED

The fuel cell "order to delivery" time exceeding all those listed above, has the greatest influence on project duration.

The start of engineering follows a 9 to 12 month period for preliminary engineering, the final selection of a gasifier technology and sufficient progress in coal testing to confirm both the raw gas composition and the selection of a design coal. This preliminary phase of work is currently scheduled to start in early 1986 and to be completed by the end of that year.

2.7 Environmental

A comparison of GFC plant emissions and the applicable regulatory limits is given in Table 7-1 of Section 7.0.

This table shows liquid emissions to be well below regulatory limits.

Due to supplementary firing of tars and oils, NO_x and SO_2 emissions are estimated to be above the tabulated EPA deminimus levels which trigger the Clean Air Act PSD permit process. However, the apparent absence of a "major source" at Fort Hood would exempt the GFC facility from these permitting requirements.

Solid wastes will be disposed of according to requirements of the Resource Conservation and Recovery Act and local laws. Noise will be controlled to meet DOA and Texas requirements during construction and during operation.

2.8 References

2-1 Westinghouse Electric Corp., "Phosphoric Acid Fuel Cell, 7.5 MWe dc Electric Power Plant Conceptual Design," WAESD TR-83-1002, May 1983.

2-2 Fluor Power Services, Inc., "Component Failure and Repair Data for Coal-Fired Power Units", EPRI AP-2071, October 1981.

3.0 PLANT GENERAL ARRANGEMENT

3.1 Configuration

The Coal Gasification/Fuel Cell/Cogeneration (GFC) plant is located approximately 4000 feet south-west of the Medical Complex.

Figure 3-1 shows the GFC plant area. Figure 3-2 shows equipment layout.

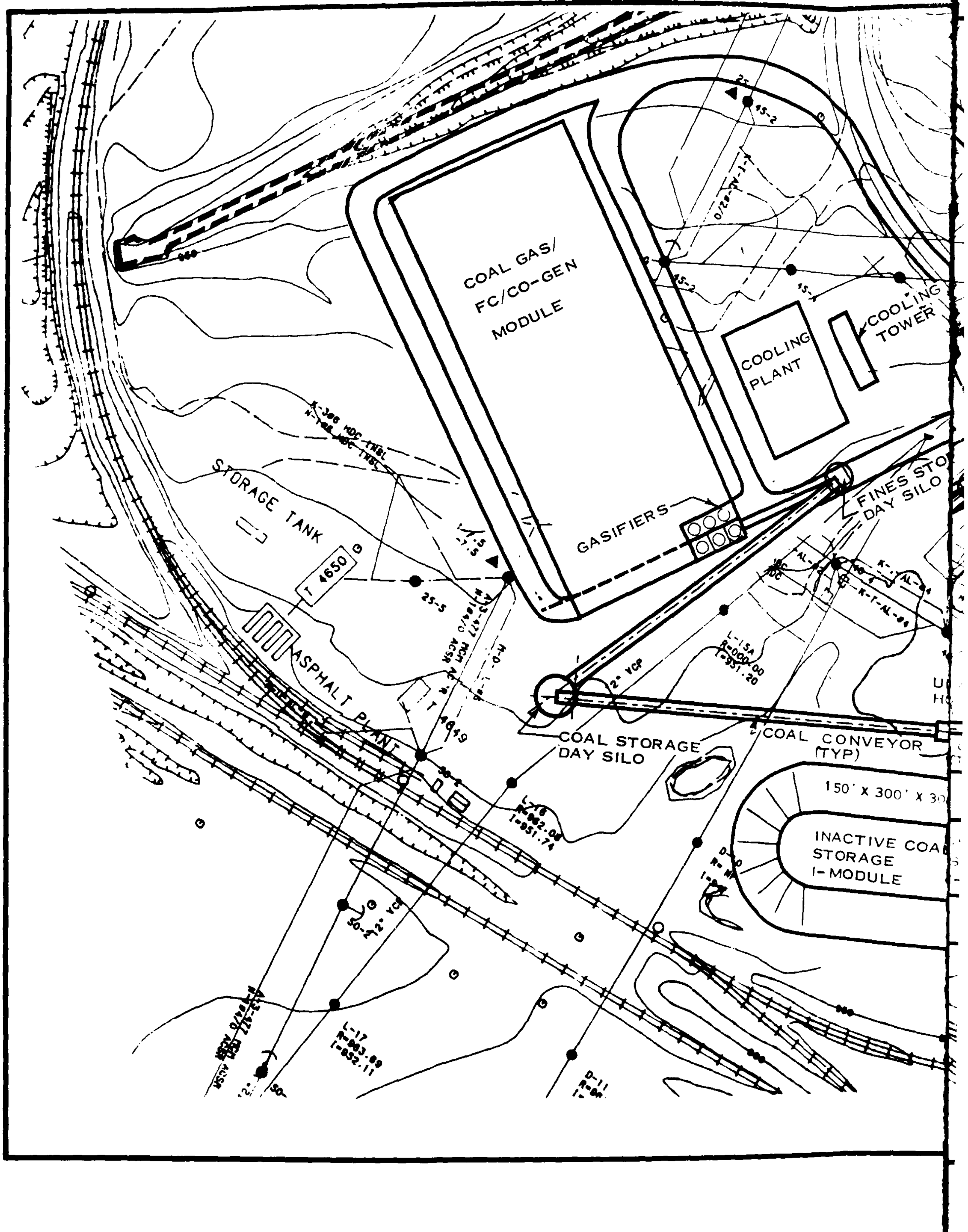
The GFC plant being studied includes one complete 11 MW module which may be followed by a second future module. The module consists of the Coal and Ash Handling Section, Gasification Section, Gas Cooling, Cleaning and Compression Section, CO Shift Section, Sulfur Removal and Recovery Section, Process Condensate Treatment Section and the Fuel Cell and Thermal Management Section and Auxiliary Systems.

In addition the following facilities are included:

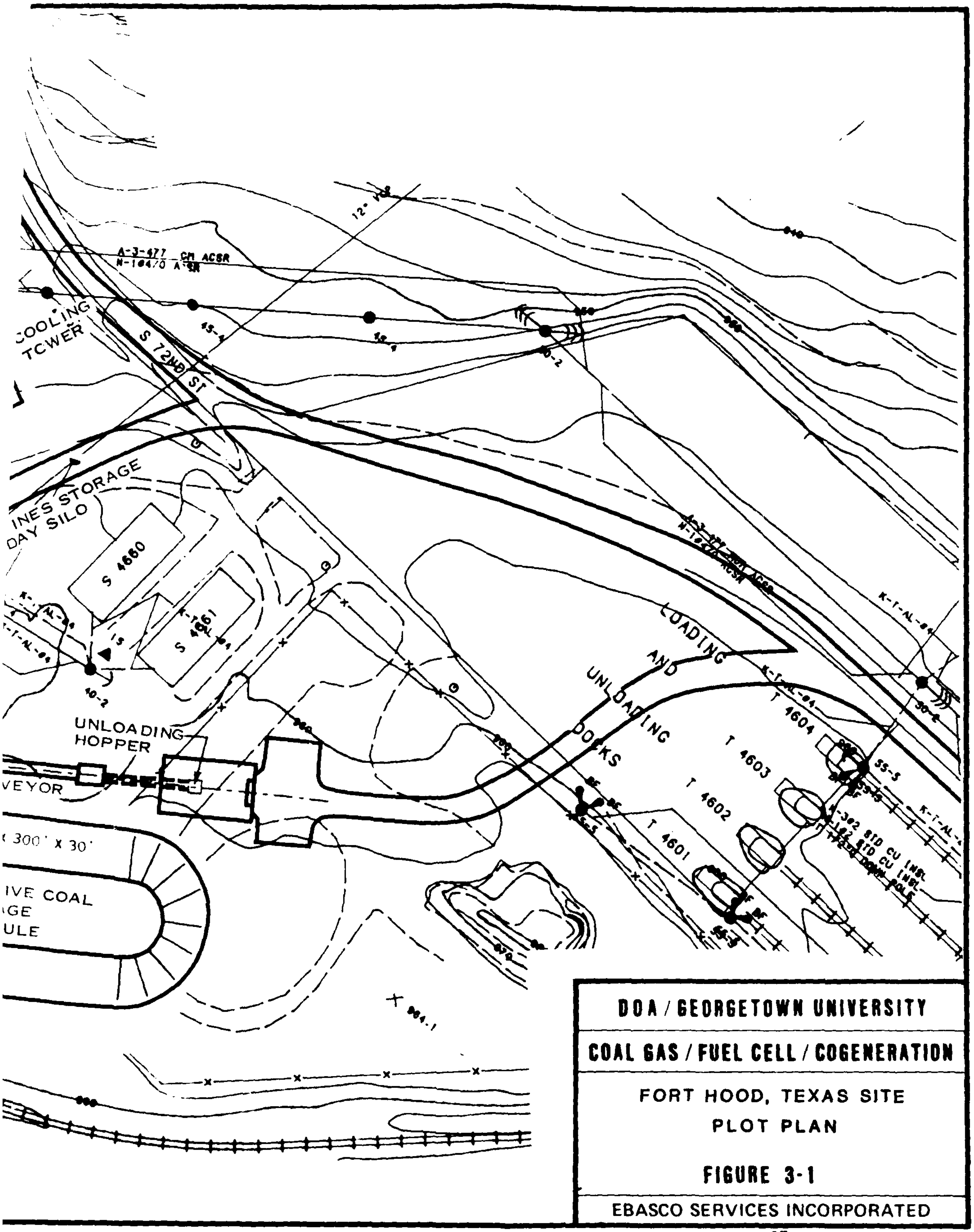
- Power Conditioners
- Transformers
- Switchgear and Motor Control Centers
- Process Condensate
- Water Treatment
- Repair Shop
- Parts Storage
- Material Storage
- Lockers

The plant is located in an open area at grade level. Excluding coal storage and adding the bounding access roads, one GFC plant module occupies an area of approximately 200 feet by 430 feet.

Coal is delivered to the site by trucks and is stored in an emergency coal pile located east of the GFC module(s). The coal pile provides 90 day storage for one GFC module. If a second module is installed the coal pile can be extended eastward to maintain this storage capacity.



COAL GAS/
FC/CO-GEN
MODULE
COOLING PLANT
COOLING TOWER
FINES STO
DAY SILO
GASIFIERS
STORAGE TANK
T 4650
ASPHALT PLANT
T 4649
COAL STORAGE
DAY SILO
COAL CONVEYOR
(TYP)
150' X 300' X 30
INACTIVE COA
STORAGE
I-MODULE



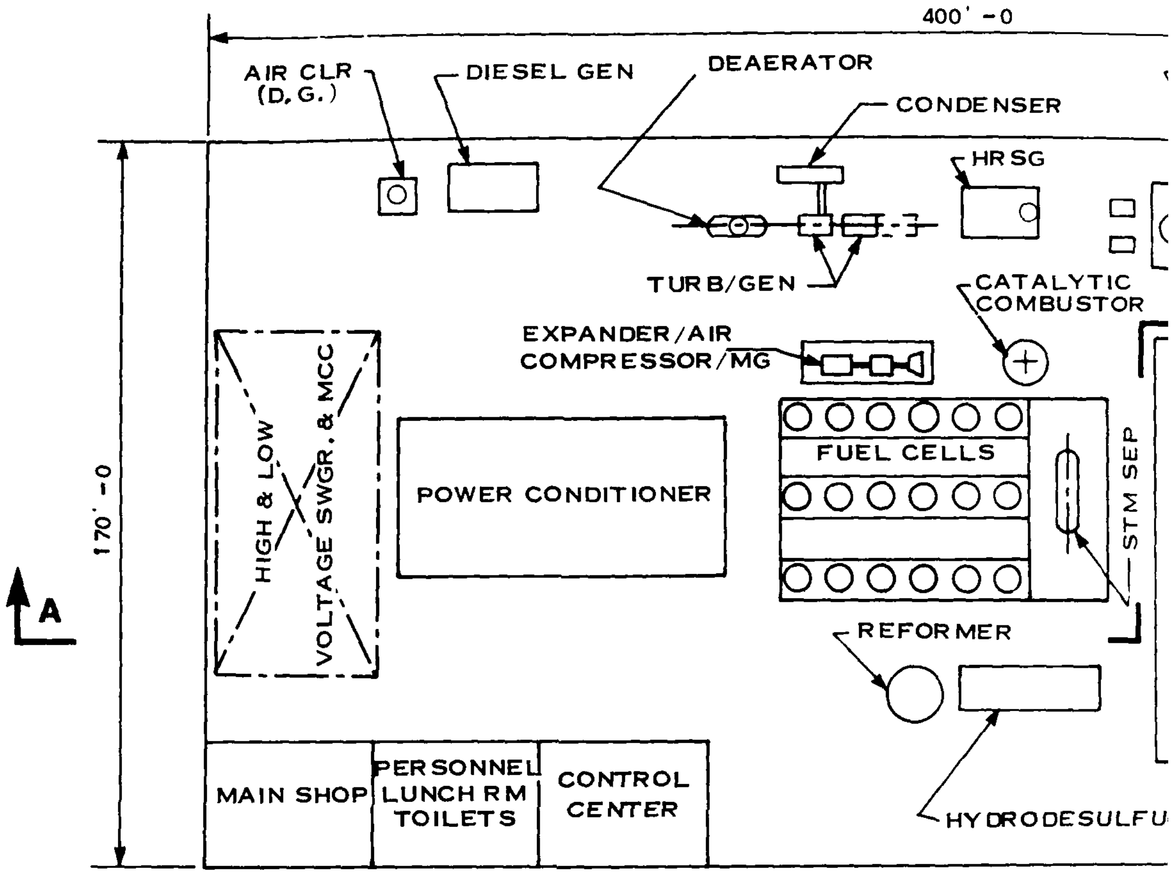
DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

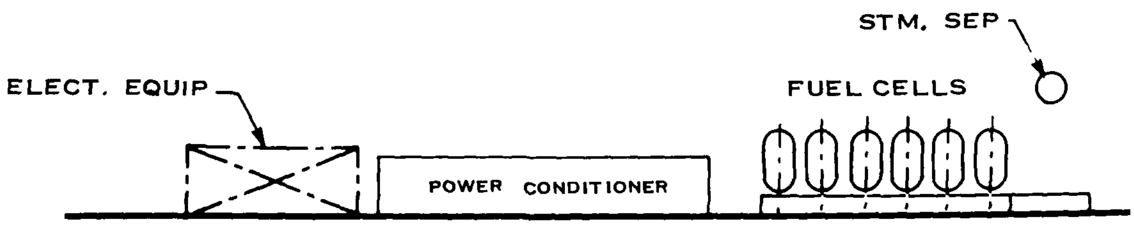
FORT HOOD, TEXAS SITE
PLOT PLAN

FIGURE 3-1

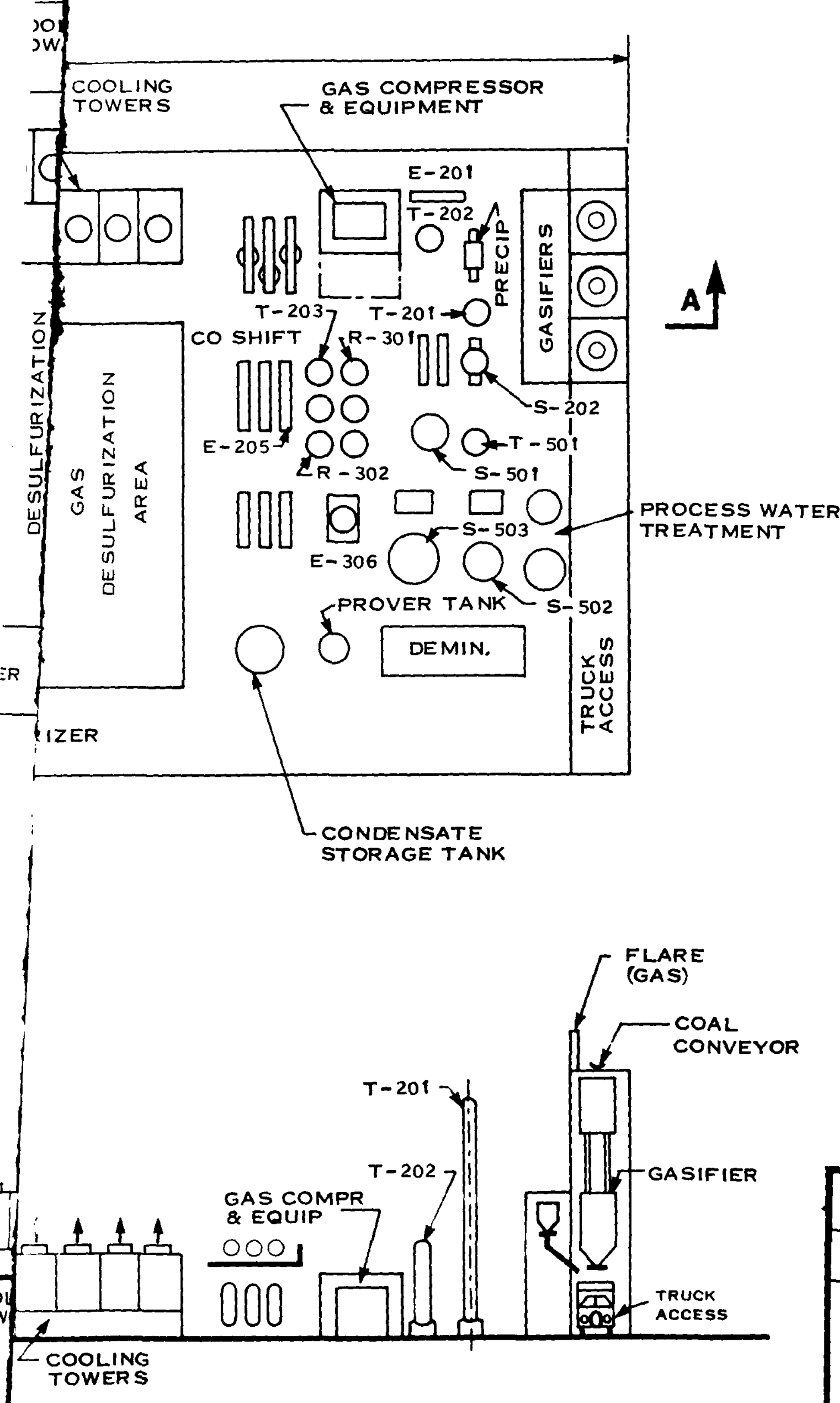
EBASCO SERVICES INCORPORATED



PLAN



SECTION A-A



DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE
GENERAL ARRANGEMENT
SCALE: 1"=40'

FIGURE 3-2

EBASCO SERVICES INCORPORATED

The contents of the gasifier ash hoppers and gasifier cyclone hoppers are unloaded directly into a truck on a daily basis for off-site dumping.

The Central Cooling and Heating Plant is housed in a structure approximately 100' by 120' that is located north of and adjacent to the GFC. the CCHP structure will include absorption chillers, chilled water pumps, hot water pumps, steam to hot water heat exchangers and plant operator facilities. The CCHP cooling towers are located on a pad north of and adjacent to the CCHP building.

All equipment is fully accessible from the ground or from platforms and arranged with adequate space for operation, maintenance and repairs. Adequate laydown space and lifting devices are provided for equipment overhaul.

Approach roads and aisles are designed for equipment removal and replacement by trucks and for access by the fire department.

The Control Center for the GFC plant is located adjacent to a service and storage Buildings and directly apposite the fuel cells.

3.2 System Interfaces

3.2.1 Electrical

Electrical connection of the Fort Hood GFC system to the Texas Power and Light Company (TP&L) grid via the Fort Hood substation, including protective relaying, generally follows industry guidelines(1) and includes any additional TP&L requirements.

The fuel cell output is connected to the substation system through a static converter which is similar in all respects to those used throughout the power industry for HVDC and variable frequency systems, except that it must be designed to accept the input voltage variations associated with the fuel cell plant.

Statistics(2) indicate that availability of HVDC converters averaged 94.6 percent (98.2 percent if maintenance outages are excluded) for the period 1977-1981. The converter is of a 12-pulse design, with filters as required to reduce the harmonic content of power output to the TP&L system. Harmonic content of the converter output must conform to the requirements of Reference 3. Power components of the converter are conservatively rated to ensure maximum reliability. The converter is completely self protecting against faults and all thyristors are protected against current and voltage surges.

In general, the converter is of modular design for ease of maintenance. Cooling is accomplished by air or water, with two full capacity cooling systems being supplied.

In addition to the fuel cell output, power to the TP&L grid is available from two additional sources. The first is from the combustor-expander receiving fuel cell vent gases and the second is the turbine receiving steam from the fuel cell cooling system and heat recovery steam generator (HRSG). The expander is provided with a motor-generator which for this application is an induction machine. The induction machine is by far the most common piece of rotating electrical equipment in existence today. It is highly reliable and simple in construction. As a motor, the induction machine is used to supply compressed air to the fuel cell cathode during start-up; however, once the expander is operational, the induction machine is used to generate electrical power. Induction generators have been successfully applied in the process industry with ratings as high as 10 MW. The motor-generator requires protective relaying for both modes of operation. This protection must be coordinated with TP&L. In addition, reactive power requirements for the machine must either be supplied by TP&L, or capacitors provided as part of the installed system.

The generator for the steam-turbine is a synchronous machine with protective relaying provided for interface with the TP&L system.

3.2.2 Other Site Utilities

All utilities to the GFC plant are metered for purposes of accounting and performance analysis.

a - Water

Fresh water supply is required for the gasifiers, the cooling tower make-up, the sulfur removal system and the Thermal Management System makeup as follows:

	Flow (gpm)
Gasifiers	6
Cooling Tower Make-up	88
Sulfur Removal System	5
Thermal Management Systems	34
Total	133

The water will be supplied from the existing city water main.

b - Natural Gas

Natural gas (300 scfm per gasifier) is required for startup heater (F-301) in the CO shift section. Additionally, 20 scfm of natural gas are required to support the ammonia flare. Natural gas supplied from the existing gas main is used during plant startups.

c - Electric Power

Electric power for the plant auxiliaries (pumps, compressors, fans, lighting, etc.) is supplied by the GFC system. Offsite power is used during plant startup.

d - Sewage

Effluent from the plant is treated to levels that meet local pretreatment requirements before discharge into the existing sanitary sewer lines.

3.3 CIVIL

At present it appears that site specific subsurface soil data (eg, boring logs, soils reports) are not readily available for the proposed site. However, based on the existing structures in the vicinity of the proposed site, the use of spread footing for equipment foundations would be a reasonable assumption at this level of study. This assumption will be used throughout the feasibility analysis unless subsequent information is received that will necessitate a change. Although not warranted at this time a comprehensive subsurface investigation program will be required to provide an adequate data base prior to final project planning and design.

3.4 References

3-1 ANSI/IEEE C37.95-1973, Guide for Protective Relaying of Utility-Consumer Interconnections

3-2 Ebasco Report PRC-HVDC-001, High Voltage Direct Current (HVDC) Reliability Study, dated February 13, 1984.

3-3 IEEE 519-1981, Guide for Harmonic Control and Reactive Compensation of Static Power Converters.

4.0 ELECTRICAL LOADS

4.1 Present Load

Currently, the Fort Hood electrical load is supplied from two TP&L 138 kV feeders to the main substation. The main substation supplies the distribution system at 12.5 kV via four transformers (3-25 MVA, all rated 138/12.5 kV).

The Fort Hood load is made up of the base load which includes the barracks, BOQ, Dental Clinic and hospital. Peak load varies with the season, with the summer peak dominant. From data available for fiscal 1984, the high monthly usage of electrical energy was 36.3 GWH in August. The low monthly usage was 14.2 GWH. These corresponded to approximate loads of 63 and 26 MW, indicating that one fuel cell module will supply approximately 18% and 40% of the Fort Hood basewide electrical demand during the summer and winter, respectively.

4.2 Future Load

The load at Fort Hood will continue to increase over current requirements. A second substation is planned to serve the load at the facility being constructed west of the Main Fort. When constructed, the new substation will be tied to the existing substation. The fuel cell facility can supply some of this load directly or alternately, sell its output at avoided ccsts.

5.0 THERMAL LOADS

5.1 Present Load

The thermal load on the GFC system has been defined as the heating and cooling requirements of the Medical Complex and the future Third Corps Headquarters Building. By reference to the ratings of existing refrigeration and heating equipment, to check figures for similar applications, and to building floor areas, the following peak design loads were estimated:

	Refrigeration (Tons)	Space Heating (MM Btu/hr)	Service[1] Water Heating (MM Btu/hr)
Medical Complex	2300	36.2	4.7
Future Third Corps HQ	1000	9.4	.5

Note

1. Includes domestic hot water and steam for hospital and kitchen equipment.

The above estimates were made in the absence of such information as operating logs, energy use data, utility bills, HVAC system type and controls, outside air loads, service water usage, etc. and are therefore subject to further review during detailed engineering.

Referring to actual monthly heating and cooling degree-day data, the above peal loads, were converted to average monthly steam flows for space heating and absorption refrigeration and plotted in Figure 5-1. the maximum and minimum monthly average steam flows are respectively 31,400 lb/hr in August and 13,400 lb/hr in April.

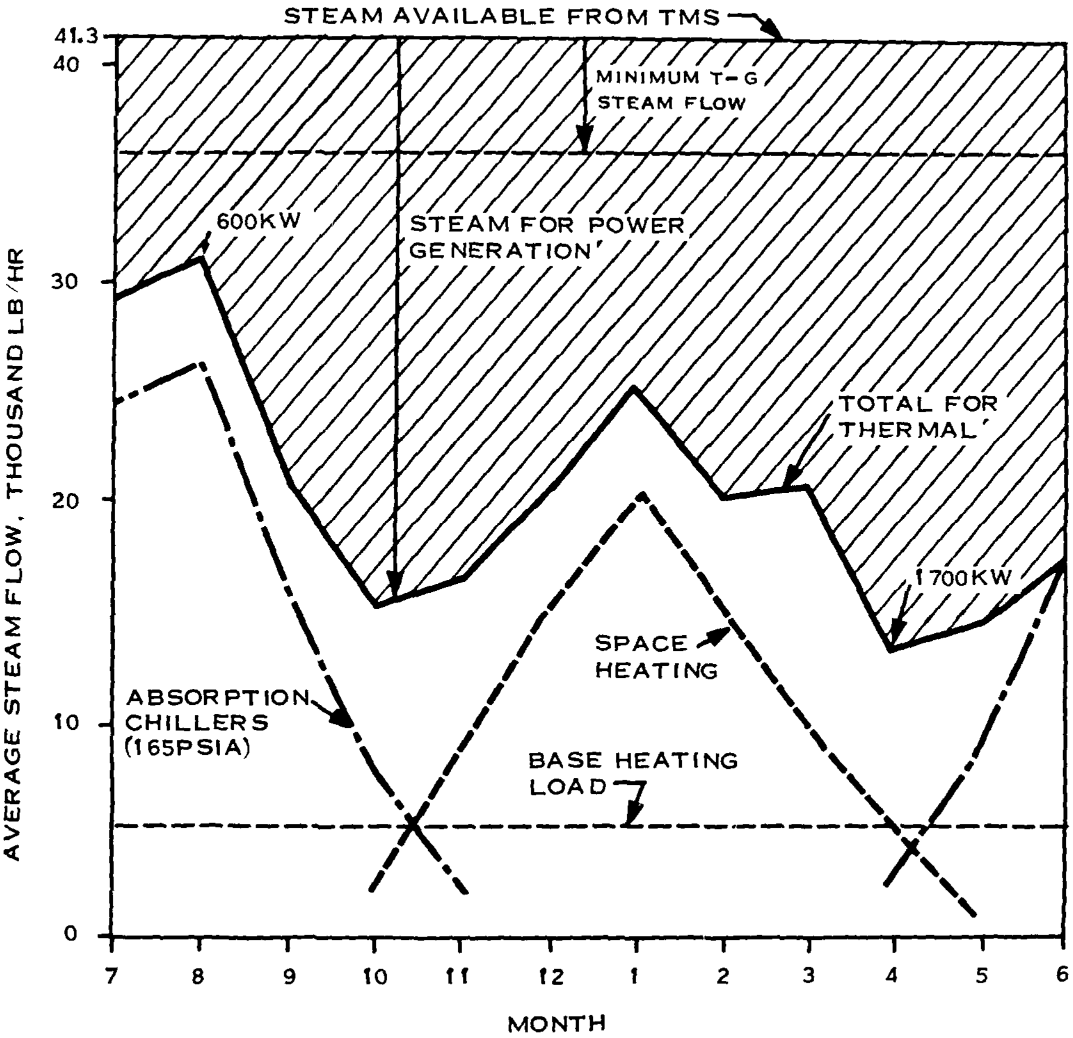


FIGURE 5-1 ESTIMATED STEAM FLOW vs MONTH
FORT HOOD, TEXAS SITE

5.2 Future Load

Based on gas consumption for 1984 listed in reference 5-1 and an assumed boiler efficiency of 75% the present average monthly heating load of Fort Hood ranges from 44,400 lb/hr (July) to 337,200 lb/hr (February) of equivalent steam. Future increases in the Fort Hood heating load will not affect GFC design, but will divert 230 psia steam from turbine-generator T-602 for use in the Central Heating and Cooling Plant.

5.3 References

5-1 Unnumbered pages entitled, "FY84 Energy Consumption" from FY85 Energy Plan.

6.0 SYSTEM DESIGN DESCRIPTION

6.1 Material Handling

6.1.1 Coal Handling

6.1.1.1 Function and Design Requirements

The function of the coal handling system is to receive, weigh, sample, screen, store, meter and distribute coal to the gasifiers. Daily coal demand for one module, consisting of three (3) gasifiers, is 286 Tons/day with all gasifiers in operation.

A live storage silo of 600 tons capacity allows approximately one day storage for two modules with all gasifiers at full rated operation or two days storage for a single module. An emergency 90 day open storage pile allows continued operation in the event of an extended interruption in coal deliveries.

6.1.1.2 System Description

The coal handling flow diagram is shown in Figure 6.1-1.

Lignite sized at (2" x 0") is delivered to the site in 20 ton trucks, with deliveries recorded at truck scale T-001.

The trucks discharge either directly on the floor of the storage area or into inground receiving hopper S-001. Water spray nozzles control the release of coal dust during truck unloading into the receiving hopper. The receiving hopper is located in an enclosed structure. Coal discharged directly onto the floor is dozed either to the emergency storage pile, or into the receiving hopper. A typical daily delivery would range from 15 to 20 trucks with one gasifying module, and 30 to 40 trucks for two modules. Belt feeder H-001, reclaims the coal from the hopper, and transfers it to belt conveyor H-002. A magnetic separator at the head end of conveyor H-002 removes tramp iron from the coal stream. Belt Weighfeeder H-012 reclaims coal from Silo, S-002 and discharges onto belt conveyor H-009. By means of a flop gate, conveyor H-009 diverts the coal either to screen H-013, which discharges onto Tripper Conveyor, H-011, or directly to Tripper Conveyor, H-011. Bypass chute connections are provided for the collection of coal samples prior to discharge to Tripper Conveyor, H-001. If an additional GFC module is installed, Tripper Conveyor H-011 can be extended to serve the additional gasifiers.

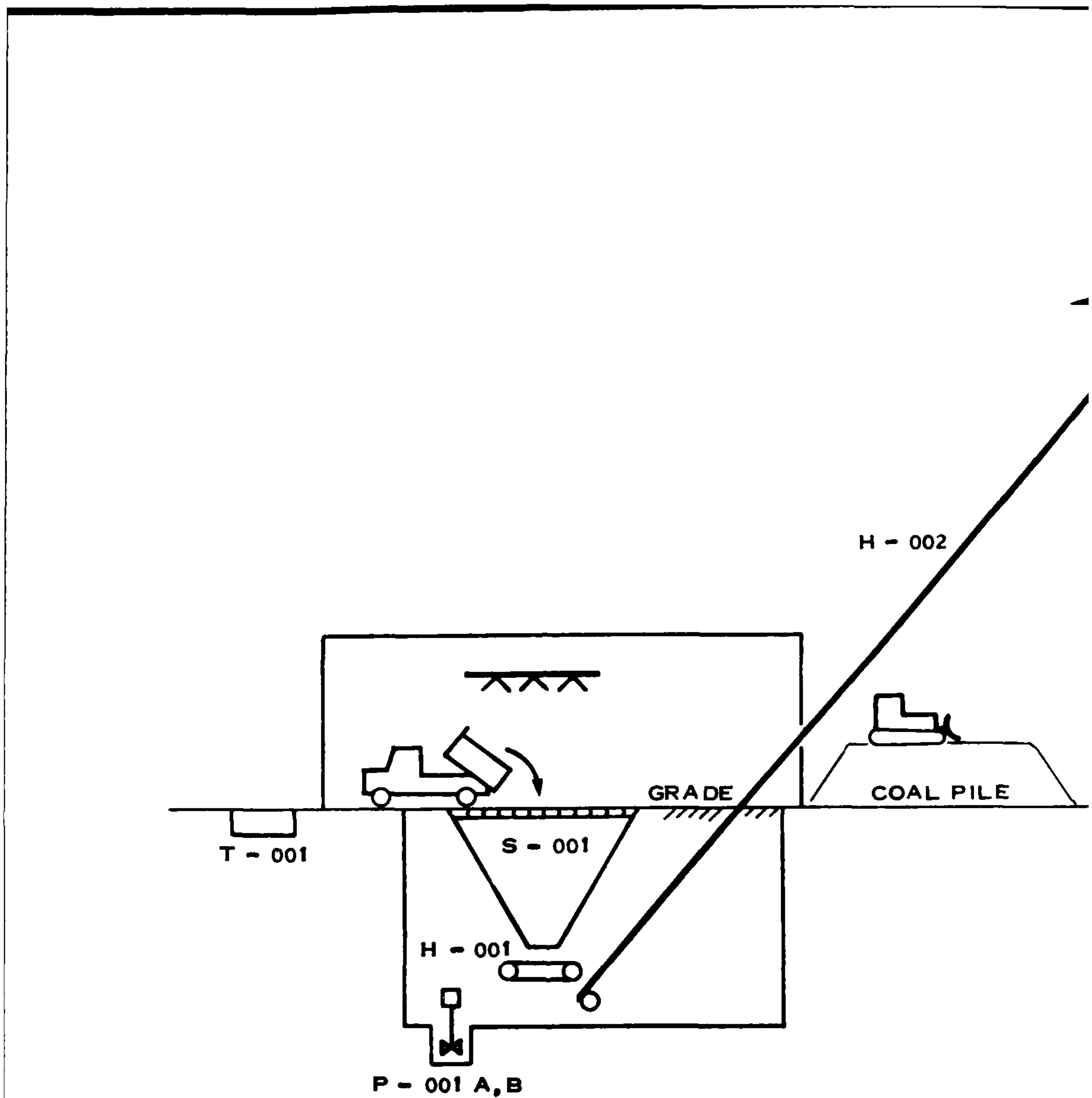
Fines less than 1/4" flow from the screen fines hopper into Silo S-003 which is sized for two days storage capacity and which discharges intermittently into enclosed trucks. A bag type dust collector controls dust generated during coal handling and prevents accumulation of methane in the coal silo.

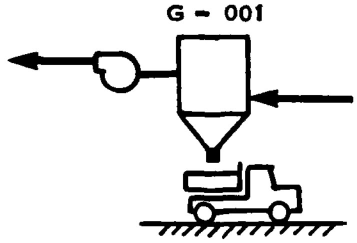
Two 100% capacity sump pumps are installed in the receiving hopper pit to remove accumulated water and any storage pile runoff. Coal dust accumulated at the gasifier area is hosed with water. The water/coal mixture is removed by two 100% capacity sump pumps. The assumption that these pumps will discharge into the existing waste water treatment system serving Area No. 10 requires confirmation.

The emergency storage pile is built up with compacted coal layers. By exclusion of oxygen, compacting reduces the probability of spontaneous combustion. Compaction also increases storage capability of the pile.

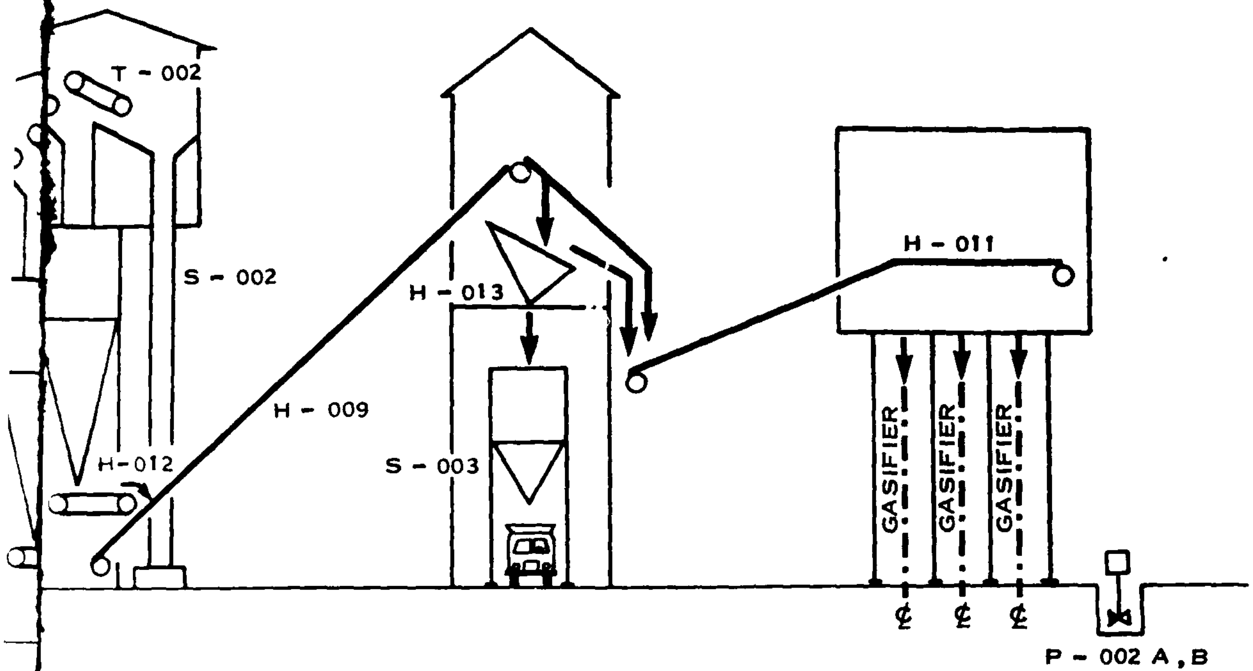
To prevent escape of coal dust during wind conditions, the storage pile is sprayed with a commercially available, crusting agent which cures in about 12 hours

Depending upon soil characteristics an impervious liner may be required under the pile to prevent leachate migration into the ground. Collecting ditches are provided along the pile periphery to collect water runoff.





COAL DUST COLLECTION SYSTEM



S - 001	RECEIVING HOPPER
S - 002	COAL SILO
S - 003	FINES SILO
G - 001	DUST COLLECTOR
H - 001	RECEIVING BELT FEEDER
H - 002	BELT CONVEYOR
H - 009	BELT CONVEYOR
H - 011	TRIPPER CONVEYOR
H - 012	SILO BELT WEIGHFEEDER
H - 013	SCREEN
P - 001	SUMP PUMP
P - 002	SUMP PUMP
T - 001	SCALE
T - 002	MAGNETIC SEPARATOR

DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE

PROCESS FLOW DIAGRAM

COAL HANDLING AND STORAGE SECTION

FIGURE 6.1-1

EBASCO SERVICES INCORPORATED

6.1.1.3 System Performance

The coal handling system consists of belt conveyors, belt feeders and chutes. Each conveyor consists of belt, idlers, pulleys, a reduction gear, holdback, coupling and an electric motor.

Conservatively designed, a long service life can be expected from these components. Preventive maintenance is simple and replacement parts can be stored at the plant.

6.1.2 Ash Handling System

6.1.2.1 Functions and Design Requirements

The function of the ash handling system is to remove ash collected in the gasifier storage hoppers. Additionally, the design considers the environmental impacts associated with the handling of powder type materials which can be a source of dust emissions.

6.1.2.2 System Description

Ash produced through the gasification of lignite is collected and stored in a conical hopper located below the revolving grate of the gasifier.

Dust or fly ash entrained in the gas leaving the gasifier is separated in a cyclone separator and collects in its conical storage hopper. Due to the high ash contant in lignite, the ash storage hopper may require unloading at least twice daily.

The cyclone hopper can collect 4.3 tons of dust in a 24 hour period, based on an hourly flow of 359 lbs/hr.

Each hopper is furnished with a sliding gate operated by a manual rack and pinion gear. Ash and dust is unloaded from their respective hoppers into a covered dump truck for offsite disposal. Prior to unloading the ash hopper, an operator floods the hopper with water and then dewaters it before opening the gate. Since lignite ash has a high CaO content, the water quench time is reduced to prevent binding of the ash and dust in the hopper. The moist material does not cause any fugitive dust emissions.

Dust collected in the cyclone hopper is stored in a wet state and unloaded with the ash into the covered dump truck.

6.1.2.3 System Performance

The ash removal and handling system utilizing truck disposal provides high reliability and availability. It is assumed that the trucking operation will be performed on a contract basis and that certain guarantees in the contract will be made to assure the maintenance of an adequate schedule for daily removal of ash and dust.

6.1.2.4 Maintenance

Operation of this system is local and manual. Manual loading of materials into containers, vehicles, etc., is the most widely used method and by far the simplest. Control of the ash hopper flood cycle is also local and operator initiated. With a proper preventive maintenance program implemented, critical components such as isolating gates should not fail during operation.

6.1.2.5 Technical Risks

Risk associated with ash and dust removal is limited to the availability of trucks to receive the ash and dust and ability of the isolating gate to operate. During inclement weather or other events which prevent trucks from removing ash and dust, dumpsters provide temporary onsite storage.

A situation where potential loss of availability may occur is when an isolating slide gate fails to open or close or is worn to its limit thereby not effectively isolating material flow. The manually operated rack and pinion gear should ensure closure and opening of the gate and a proper maintenance program should detect blade wear prior to malfunction.

6.2 Coal Gasification

6.2.1 Functions and Design Requirements

The function of the Coal Gasification Section is to convert coal energy to gaseous form suitable for processing prior to its use in a fuel cell.

The controlling design criteria for the Coal Gasification Section is the concentration of carbon, hydrogen and volatile matter in the design coal. The feedstock used for this study is a Texas lignite with composition and characteristics shown in Table 6.2-1.

Design capacity of the gasifier is based on the United Technologies fuel cell requirement of 775 mols of hydrogen per hour.

A fixed bed air blown atmospheric single stage Wellman-Galusha gasifier was selected as the basis for this study. This selection was based primarily on the decision to use fully commercialized technology. The Wellman-Galusha gasifier having been in use for 50 years has a large data base of technical and economic information. Another criteria for gasification technology selection was the size of the gasifier. This fuel cell system requires a relatively small gasification plant eliminating larger gasifiers from use in this application.

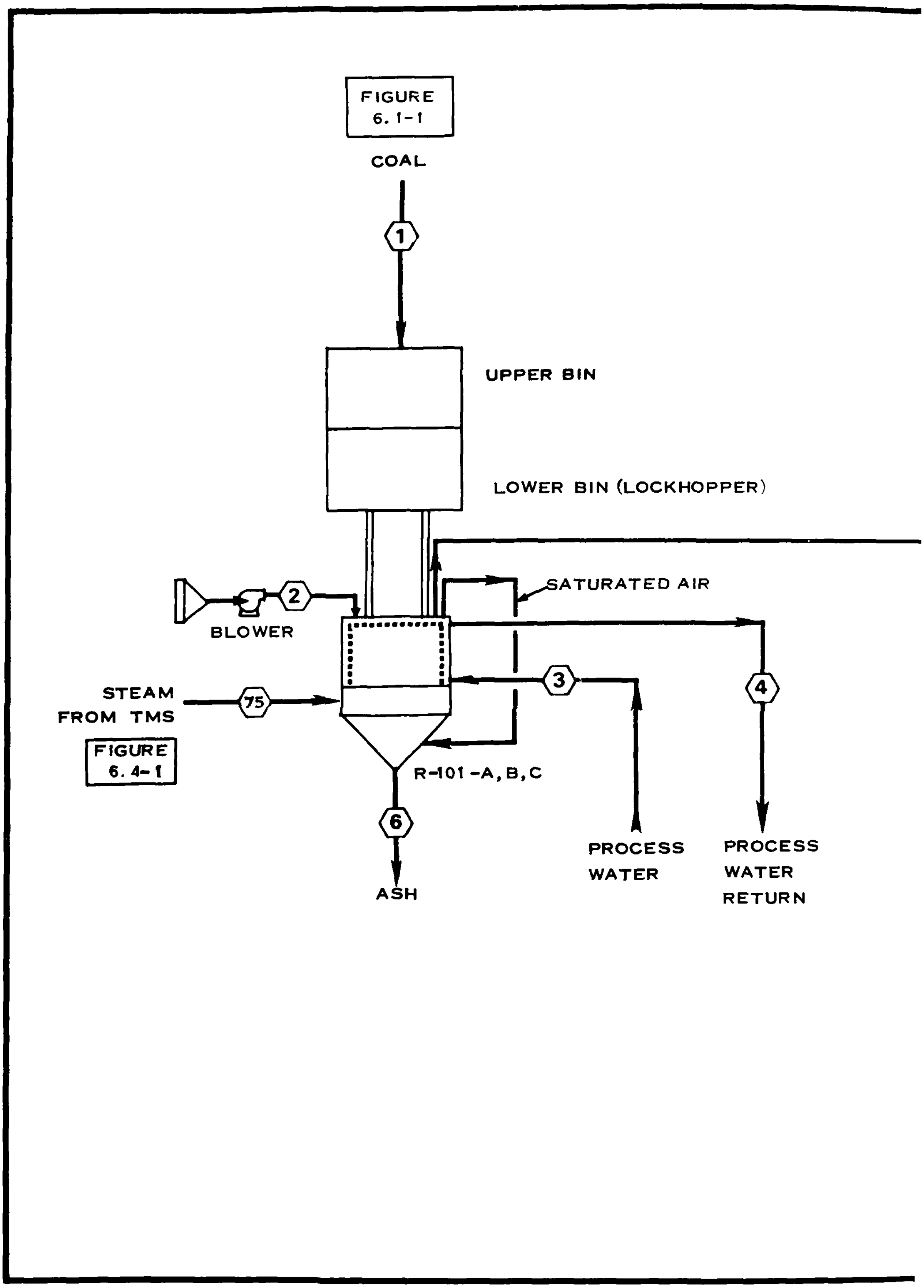
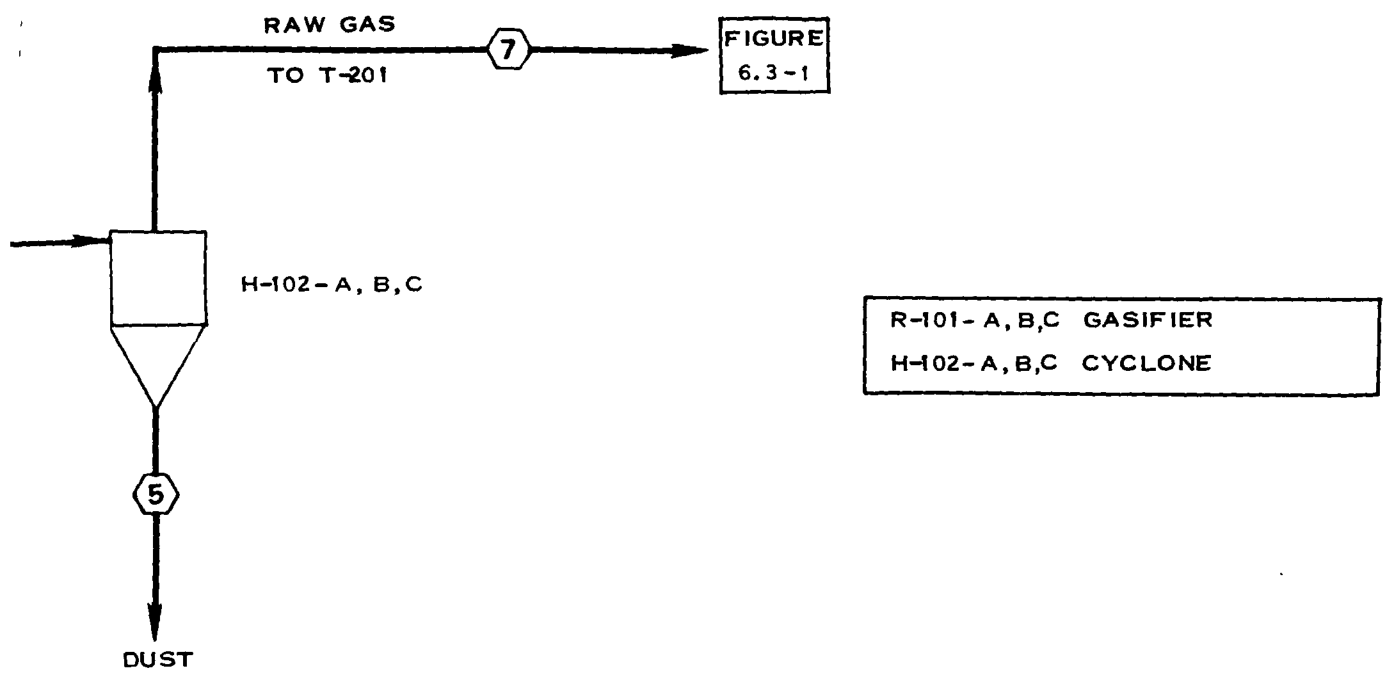


FIGURE
6.1-1
COAL
1
UPPER BIN
LOWER BIN (LOCKHOPPER)
SATURATED AIR
2
BLOWER
STEAM
FROM TMS
75
FIGURE
6.4-1
3
4
R-101-A,B,C
6
ASH
PROCESS
WATER
PROCESS
WATER
RETURN



DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE
PROCESS FLOW DIAGRAM

COAL GASIFICATION SECTION

FIGURE 6.2-1

EBASCO SERVICES INCORPORATED

In addition, the Wellman-Galusha unit is able to process coal with a Free Swelling Index up to 5 covering a wider range of coals than comparable technologies.

The raw gas composition produced by the Wellman-Galusha gasifier from the design coal is shown in Table 6.2-2.

The total consumption of coal is 286 T/Day producing 2,728 million Btu/day of coal gas at a gasification efficiency of 69.6%. If the heating value of tars and oils is included, the gasification efficiency is 85%.

The material balance for the gasifier is given in Table 6.2-3.

TABLE 6.2-1

COAL ANALYSIS

o COAL (TEXAS LIGNITE)

Proximate Analysis (as received, %)	
Moisture	32.25
Ash	15.13
Volatiles	29.81
Fixed Carbon	22.81
Ultimate Analysis (dry basis %)	
Carbon	56.03
Hydrogen	4.13
Nitrogen	1.07
Sulfur	1.56
Chlorine	.03
Ash	22.34
Oxygen (by diff)	14.84
High heating value (as rec'd Btu/Lb)	6718
Ash Fusion, Initial Def (°F)	2327
Free Swelling Index	Less than 1

TABLE 6.2-2

RAW GAS COMPOSITION

	Mol %	(Dry Basis)
H_2	19.25	
CO_2	6.84	
C_2H_4	0.18	
C_2H_6	0.12	
N_2	45.40	
CH_4	1.65	
CO	26.16	
H_2S	0.29	
COS	0.04	
NH_3	0.06	
HCN	0.01	
	100.00	

Water Yield Lb/Lb Coal	0.48
Tar Yield Lb/Lb Coal	0.06
Gas Temperature °F	480

TABLE 6.2-3

GASIFIER MATERIAL BALANCE

		LB/HR
INPUT		
Coal Feed (As received)		23,857
Air, Dry		29,821
Steam		5,964
	Total	59,642
OUTPUT		
Dry Gas		41,990
Tars and Oils		1,434
Water Vapor		11,472
Ash Purge		3,655
Cyclone Dust		359
Unaccounted		732
	Total	59,642

6.2.2 System Description

The process flow diagram for the gasification system is shown on Figure 6.2-1 and the mass balance in Table 6.2-4.

At the top of each Wellman-Galusha gasifier (R-101 A & B) is an open coal bunker or "upper bin". Following that in the downward direction is a gas tight lower coal bin or "lockhopper" in the gasifier reactor vessel and finally, the ash cone at the bottom[2][3].

The upper bin is filled by the bucket elevator and discharges coal by gravity into the lower bin. The lower bin has interlocking gas tight valves top and bottom configured such that the bottom valves close before the top valves open, and vice versa. The upper valves open, allowing coal to flow by gravity into the lockhopper. When the lockhopper is filled, usually in a matter of a few minutes, the valves are cycled, closing the upper valves and opening those at the bottom.

The lower fuel valves are kept open, except for refueling, to assure a continuous supply of fuel into the gasifier reactor vessel.

The gasifier R-101 is a double wall cylindrical vessel, with an inner shell of one inch thick steel. A water jacket surrounds the side of the inner shell and extends over the top. About four inches above the top of the inner wall there is an overflow pipe which prevents the water from completely filling the space between the inner and outer shell at the top of the vessel. Cooling water is introduced into the water jacket at the top of the vessel, and flows out through the overflow.

Air to sustain combustion is supplied by a blower. After absorbing moisture as it passes over the open water surface in the top of the water jacket, the air enters the gasifier vessel from below the grate plates, flowing upward through the ash bed. The moisture carried by the air flow moderates the temperature of the fire bed preventing the formation of clinkers. The amount of water vapor absorbed depends upon jacket water temperature which is controlled by varying cooling water flow. Additional steam is injected at the bottom of the gasifier. The water vapor thus introduced reacts chemically with the hot carbon generating gaseous products.

Coal flowing down through the feed pipes enters the top of the gasifier and is contacted by the upward flow of hot gas produced in the gasifier reactor. The heat from the countercurrent flow of hot gas first evaporates moisture, then drives off volatiles from the incoming coal. The moisture and volatile matter become part of the outward bound gas stream. The dry, devolatized coal char continues its slow downward flow through the gasifier at a rate determined by the air flow into the unit which, in turn, sets the gasification rate. The coal char passes through two stages. The first stage consists of a reducing zone, where carbon dioxide produced from char which is burning below is reduced to carbon monoxide. Water vapor is also reduced in this zone by the hot carbon in the char, producing hydrogen and additional carbon monoxide. The heat supporting this endothermic reaction is produced by the first zone directly below, wherein the carbon in the char is burned to form carbon dioxide.

The burning coal in the fire zone rests upon a bed of ash produced by the combustion of the coal char, and this bed of ash in turn is supported by a slowly revolving set of eccentric grates.

Ash removed from the gasifier vessel by the revolving grate drops into an ash cone at the bottom of the vessel. From there it is flushed out periodically with water into a truck. Flushing the ash is of a few minutes duration and does not interfere with the normal operation of the gasifier.

The depth of the ash and fire zones is monitored by the insertion of rods through pokeholes located on top of the gasifier. Steam sealed pokeholes will be used to prevent gas leaks during the poking operations.

The hot gas produced in the gasifier contains some particulates, some moisture, and volatile matter, principally aerosol tar and oil. The hot gas flows through tangential entry dust cyclone H-402, which separates particulates from the gas stream. The hot gas then flows directly to gas cleaning equipment. Composition of the gas at this point is shown in Table 6.2-2[3].

The cyclone is designed to be used as a water sealed gas shut-off valve and provides a positive leak-proof shut-off without the use of a mechanical valve. The separated particulates are stored in the cyclone cone section and flushed into a truck at the same time the wet ash is unloaded from the gasifier, in order to minimize dust emissions.

6.2.3 System Performance

The Wellman-Galusha gasifier is rated at a capacity of 8000 lbs/hr lignite when provided with an agitator. In commercial operation, the gasifier has processed as little as 7.5 pounds of coal per square foot of grate per hour or about 9% of capacity. This makes it possible to operate the gasifier without venting the excess gas to atmosphere when the demand is small. The gasifier can be operated at part load without a loss in efficiency[4]. The gasifier has no refractory lining in the gas making chamber, eliminating liner maintenance, a primary cause of shutdown for other types of gasifiers. A two week scheduled annual shutdown for maintenance with an estimated three days of unscheduled shutdown brings the estimated availability of the gasifier to 95%. Gasification will proceed at a total coal flow rate of 23,857 lbs/hr to three modules each operating at 99.4% capacity based on the material balance in Table 6.2-3.

6.2.4 Maintenance

The maintenance work anticipated for the section is minimal and requires the daily flushing of the gasifier jacket. During the scheduled two week annual shutdown, repair or replacement is made as required of the moving grates, bearings, or other moving parts. Lockhopper disk valves are cleaned and poke hole seal valves are checked.

TABLE 6.2-4

MASS BALANCE - COAL GASIFICATION SECTION

Stream No.		1	2	3	4	5	6	7	75
Stream Name		Coal	Air	Gasifier Jacket Water Inlet	Gasifier Jacket Water Outlet	Cyclone Dust	Ash Purge	Producer Gas	Steam to Gasifier
Components	MW		Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016							337.76	
CO_2	44.010							120.01	
C_2H_4	28.032							3.16	
C_2H_6	30.048							2.11	
N_2	28.016		816.31					796.58	
CH_4	16.032							28.95	
CO	28.011							459.00	
H_2S	34.080							5.09	
COS	60.070							0.70	
NH_3	17.030							1.05	
HCN	27.030							0.18	
O_2	32.000		216.99						
Ar	39.948								
H_2O (Water)	18.016			2,148.48	1,991.29				
H_2O (Steam)	18.016		16.60					636.77	157.20
Total Flow	Lb Mol/Hr		1,049.90	2,148.48	1,991.29			2,391.36	157.20
Total Flow	Lb/Hr		30,120	38,707	35,875				2,832
Solids	Lb/Hr	23,857				359	3,655		
Tar	Lb/Hr							1,434	
Pressure	Psia		14.7					15	25
Temperature	°F		70	90	165			480	240

6.2.5 Technical Risks

The mechanical components of the gasifier can be considered as potential technical risks. These components include the coal feed system and the moving grates. However, potential problems in these areas have been virtually eliminated by design improvements made in the course of many commercial applications(4).

The coal feeding system has no moving parts, thus eliminating the problems common to machines where mechanical devices are used on highly abrasive fuels. The design features now include replaceable bushings and oversized ball thrust bearings with oil and grease dams for the revolving grate assembly. Because of such design features the technical risk for the mechancial components is minimal.

Consideration must be given to the possibility that the feed coal contains more fines than can be tolerated by the gasifier. The Wellman-Galusha gasifier can accept up to 15% of its coal feed in sizes below 1/4 inch. If the percentage of fines exceeds 15%, the pressure differential across the coal bed can be excessive, and there can occur a high carryover of ungasified coal into the cyclone. This condition can have a significant impact on the efficiency of operation. To eliminate this risk, an additional set of coal sieves located at the gasifier coal bins, is included in the design of the plant.

6.2.6 References

6.2-1 Synthetic Fuels Associates, Inc, "Coal Gasification: A Guide to Status, Applications and Economics", EPRI AP-3109, June 1983.

6.2-2 Wellman Gasification Technology - Technical Manual

6.2-3 Personal Communication with Dravo Engineers, Inc.

6.2-4 Wellman-Galusha Gas Producers, Dravo

6.2-5 Gas Engineers Handbook, the Industrial Press, 1965

6.3 GAS PROCESSING

6.3.1 Functions And Design Requirements

The function of the Gas Processing System is to cool, clean and compress the gasifier effluent and then convert it to a hydrogen rich, sulfur free stream suitable as feed for the fuel cell. This section also includes a Process Condensate Treatment Section, where the toxic and organic matter are removed from the process waste water to satisfy environmental requirements before discharge.

The design criteria for the Gas Processing System is the anode feed gas specification given in Table 6.4-1. The design criteria for the Process Condensate Treatment Section is the waste water effluent specification, given in Table 6.3-1.

6.3.2 System Description

The Gas Processing System includes the following sections:

- Gas Cooling, Cleaning and Compression
- CO Shift
- Sulfur Removal and Recovery
- Process Condensate Treatment

The gasifier effluent is at 480°F and contains vapors of tars, oils, phenol, ammonia and particulates that must be removed before further processing. By cooling the gas the hydrocarbons condense and are easily removed by physical separation processes(2). The series of processes used to clean and cool the gas, the direct cooling by spraying with water followed by removal of condensed hydrocarbons in an electrostatic precipitator, have been traditionally used and improved over the years in the coke oven industry and fixed bed gasifiers product gas cleaning(1).

TABLE 6.3-1

TREATED PROCESS EFFLUENT CHARACTERISTICS(1)

	mg/l
COD(2)	150
Phenol	0.3
HCN	0
NH_3	1
H_2S	0
Suspended Solids	20

Notes:

1. Personal communication with Zimpro Environmental Control Systems.

2. COD = Chemical Oxygen Demand.

In the CO Shift Section the hydrogen (H_2) concentration in the gas is adjusted to the requirements of the fuel cell by conversion of the carbon monoxide (CO) to H_2 by reaction with steam over a catalyst.

The presence of sulfur compounds in the fuel gas led to the selection of a highly active sulfur tolerant chromium-molybdenum (COMO) shift catalyst. The catalyst is activated by small amounts of sulfur in the gas and is active within a wide range of temperatures. Part of the carbonyl sulfide (COS) present in the gas is hydrolized in the process and converted to H_2S and CO_2.

Another option was to remove the sulfur compounds first and use a conventional iron-chromium catalyst for the CO Shift reaction.

The choice of a sulfided shift process was determined by the selection of the Sulfur Removal process, which does not remove the carbonyl sulfide (COS) present in the gas. This sulfur compound, even in trace amounts, would poison a conventional CO Shift catalyst.

A two stage shift reaction with the second bed operating at lower temperatures was selected for this application. Both reactions, the CO shift and the COS hydrolysis take place simultaneously, but the bulk of COS hydrolysis occurs in the second bed. This design will achieve the desired CO conversion and will reduce the COS concentration in the gas to about 30 ppm by volume.

The specifications for the anode fuel require a maximum sulfur content of 4 ppm (Vol). Virtually, total sulfur removal from the gas must be achieved.

There are a number of sulfur removal processes commercially available, for treating the H_2S bearing gases(3)(4). These processes include chemical and physical absorption systems, which remove the sulfur compounds from the gas down to the desired level.

The physical absorption processes require low temperature operation and high H_2S partial pressure. The chemical absorption processes are not selective and remove CO_2 with the H_2S. The regeneration of the solvent requires large steam consumption to strip the absorbed gases, especially with the addition of CO_2.

The selection of a sulfur removal process was based on gas composition considerations. The gas produced by an atmospheric gasification such as the Wellman-Galusha gasifier has a very low H_2S partial pressure due to the dilution of the gas with the nitrogen from the air used in the gasification process and the relatively low gas pressure, even after compression to 160 psia. This low H_2S partial pressure eliminates the physical absorption systems as possible process choices. The chemical absorption processes are a costly alternative for the sulfur recovery process due to the high CO_2 concentration in the gas (25% Vol).

Therefore, a Stretford liquid oxidation process was chosen for this plant. In this process, the H_2S in the gas is absorbed in a solution where it is chemically oxidized to sulfur and water. The sulfur is separated from the solution, which is regenerated by air-sparging and recycled.

Because the Stretford process cannot remove COS, a hydrolysis step is required to convert the remaining COS to H_2S. A highly active catalyst, Haldor Topsoe CKA activated alumina was used to reduce the COS to levels accepted by the fuel cell operation. This catalyst can promote hydrolysis effectively at a relatively low temperature.

The traces of H_2S in the gas are removed in a polishing step over Zn oxide beds.

The condensate from the gas cooling section contains phenols, ammonia, cyanides and hydrogen sulfide. To prevent the buildup of these products in the circulating waste water, a purge stream is removed from the process condensate and discharged as waste water effluent. Before being discharged the waste water is treated for the removal of the pollutants. Two processes were considered to be used for this purpose; the Wet Air Oxidation Process (WAO) and the Powdered Activated Carbon Treatment

(PACT)[8]. The PACT process uses powdered activated carbon in conjunction with conventional biological treatment to remove contaminants and was selected to be used in this plant because it has substantially lower investment costs than the Wet Air Oxidation Process for this size unit.

Process Description

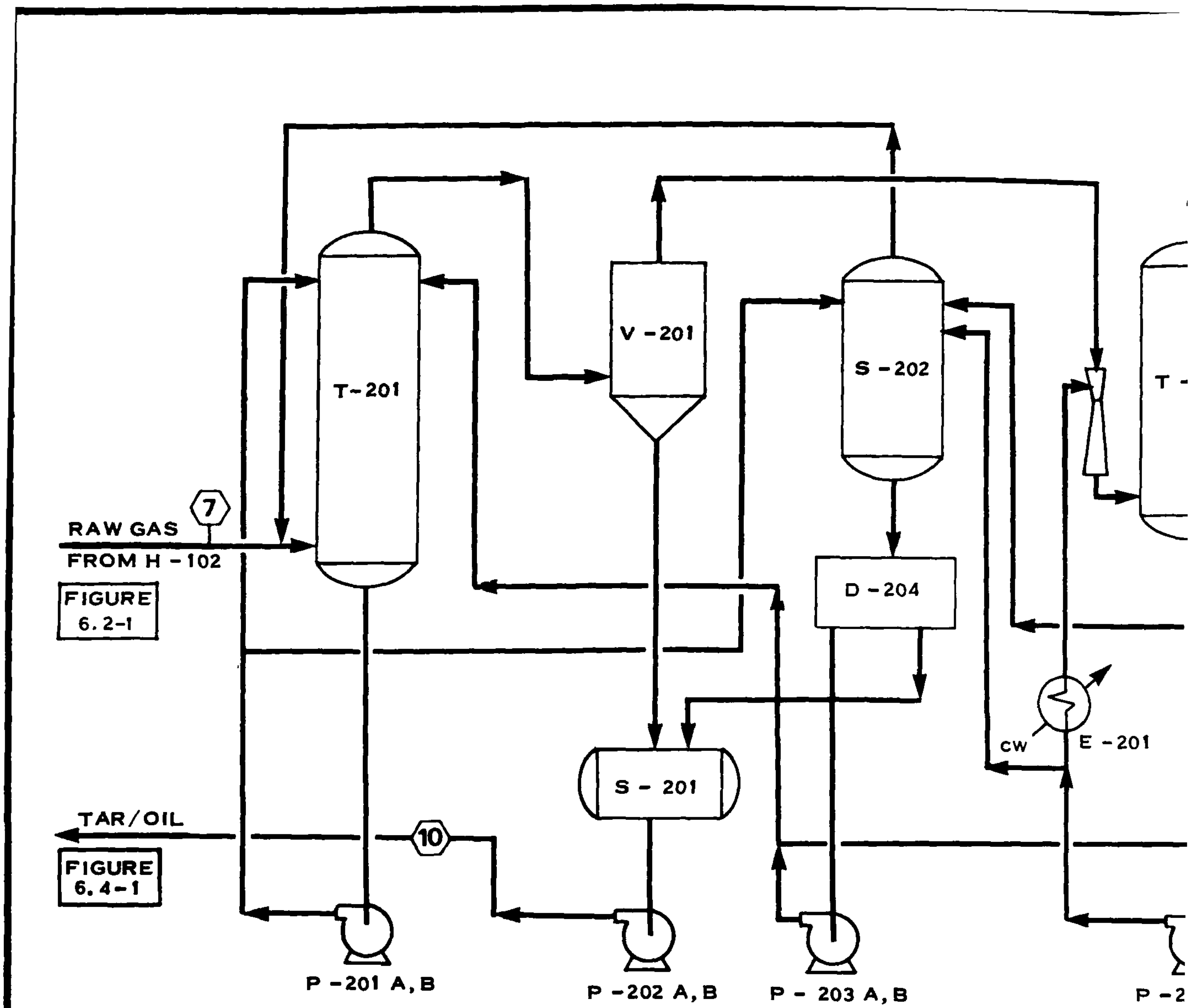
Gas Cooling, Cleaning and Compression

The configuration of the Gas Cooling, Cleaning and Compression Section is given in Figure 6.3-1 and the Mass Balance in Table 6.3-2.

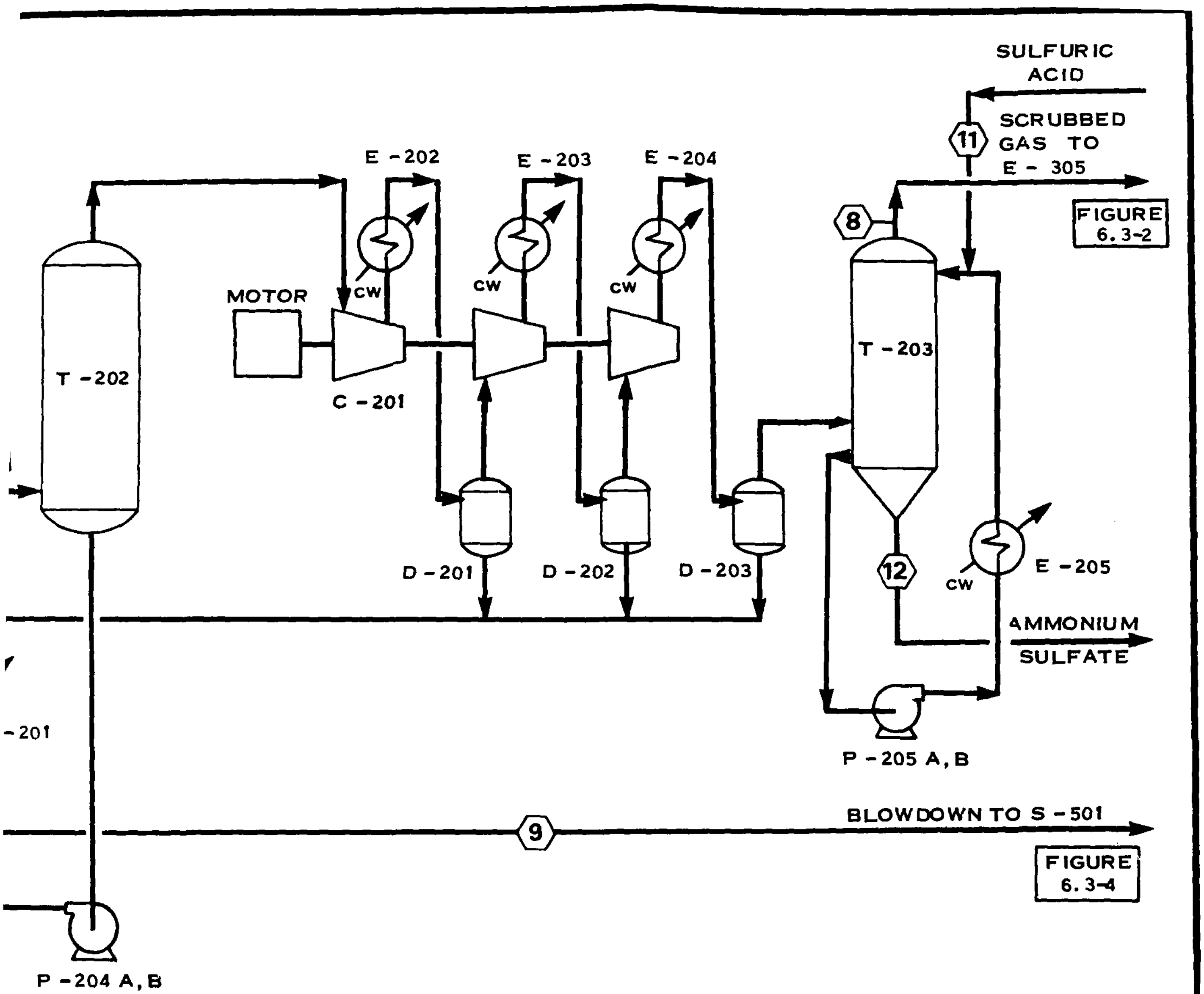
The hot gases leaving the gasification section contain some entrained particulates as well as vaporized tars and oils. The gases are first adiabatically cooled to saturation by recirculating liquor through the saturator, T-201. This direct contact water quench condenses the vaporized tars and oils, mixes the oily droplets with the scrubber water and removes additional particulates. The larger drops of oil are removed by the liquor and the smaller sized particles remain entrained in the gas. Remaining mist and particulate matter are removed in the dispersed phase electrostatic precipitator, V-201. In the electrostatic precipitator the negatively charged particles dispersed in the gas are attracted to the positively charged collecting elements and discharged from the system.

Final cooling of the gas is effected in primary cooler, T-202 by contacting the gas in a venturi jet with externally cooled circulating liquor. The cooling causes further condensation of hydrocarbons and water vapor.

Purge streams from the circulating saturation liquor and primary cooler combined with that from gas compression intercooler KO drums, are delivered to the liquid phase electrostatic precipitator, D-204 via the liquor collection tank, S-202 for separation of tars and oils. The gas phase is recycled to the saturator. The tars and oils separated by gravity from the water in D-204 are combined with those removed in the



T-201	SATURATOR	P-201 A,B	SATURATOR PUMP
V-201	DISPERSED PHASE PRECIPITATOR	S-201	TAR COLLECTION TANK
D-204	TAR SEPARATOR	P-202 A,B	TAR PUMP
S-202	LIQUOR COLLECTION TANK	P-203 A,B	LIQUOR PUMP
		P-204 A,B	PRIMARY COOLER PUMP
T-202	PRIMARY COOLER	D-201	1ST STAGE K.O. DRUM
C-201	GAS COMPRESSOR	D-202	2ND STAGE K.O. DRUM
E-202	1ST STAGE INTERCOOLER	D-203	3RD STAGE K.O. DRUM
E-203	2ND STAGE INTERCOOLER	P-205 A,B	ACID CIRCULATION PUMP
E-204	3RD STAGE INTERCOOLER	E-205	AMMONIUM SULFATE SATURATOR COOLER
T-203	AMMONIUM SULFATE SATURATOR		



DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE
PROCESS FLOW DIAGRAM
GAS COOLING, CLEANING AND
COMPRESSION SECTION
FIGURE 6.3-1

EBASCO SERVICES INCORPORATED

TABLE 6.3-2

MASS BALANCE - GAS COOLING, CLEANING AND COMPRESSION SECTION

Stream No.		7	8	9	10	11	12
Stream Name		Producer Gas	Compressed Gas	Process Condensate Blowdown	Tars/Oils	Sulfuric Acid	Ammonium Sulfate
Components	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016	337.76	337.76				
CO_2	44.010	120.01	120.01	1.61			
C_2H_4	28.032	3.16	3.16				
C_2H_6	30.048	2.11	2.11				
N_2	28.016	796.58	796.58				
CH_4	16.032	28.95	28.95				
CO	28.011	459.00	459.00				
H_2S	34.080	5.09	5.09				
COS	60.070	.70	.70				
NH_3	17.030	1.05	-	0.78			
HCN	27.030	0.18	0.18				
O_2	32.000						
Ar	39.942						
H_2O (Water)	18.016			626.77			
H_2O (Steam)	18.016	636.77	11.0				
Total Flow	Lb Mol/Hr	2,391.36	1,761.93	629.16			
Total Flow	Lb/Hr						
Tars/Oils	Lb/Hr	2,163			1,434		
Sulfuric Acid	Lb/Hr					14	
Ammonium Sulphate	Lb/Hr						18
Pressure	Psia 15	15	167	17			
Temperature	°F	480	100	100			

electrostatic precipitator V-201 and maintained in a liquid state in the steam heated tar collection tank, S-201. From here, the tar/oil is pumped off site. Part of the water overflow from the tar separator D-204 is circulated to the saturator to maintain water balance. The remaining overflow serves as system blowdown and is sent to the Process Condensate Treatment Section.

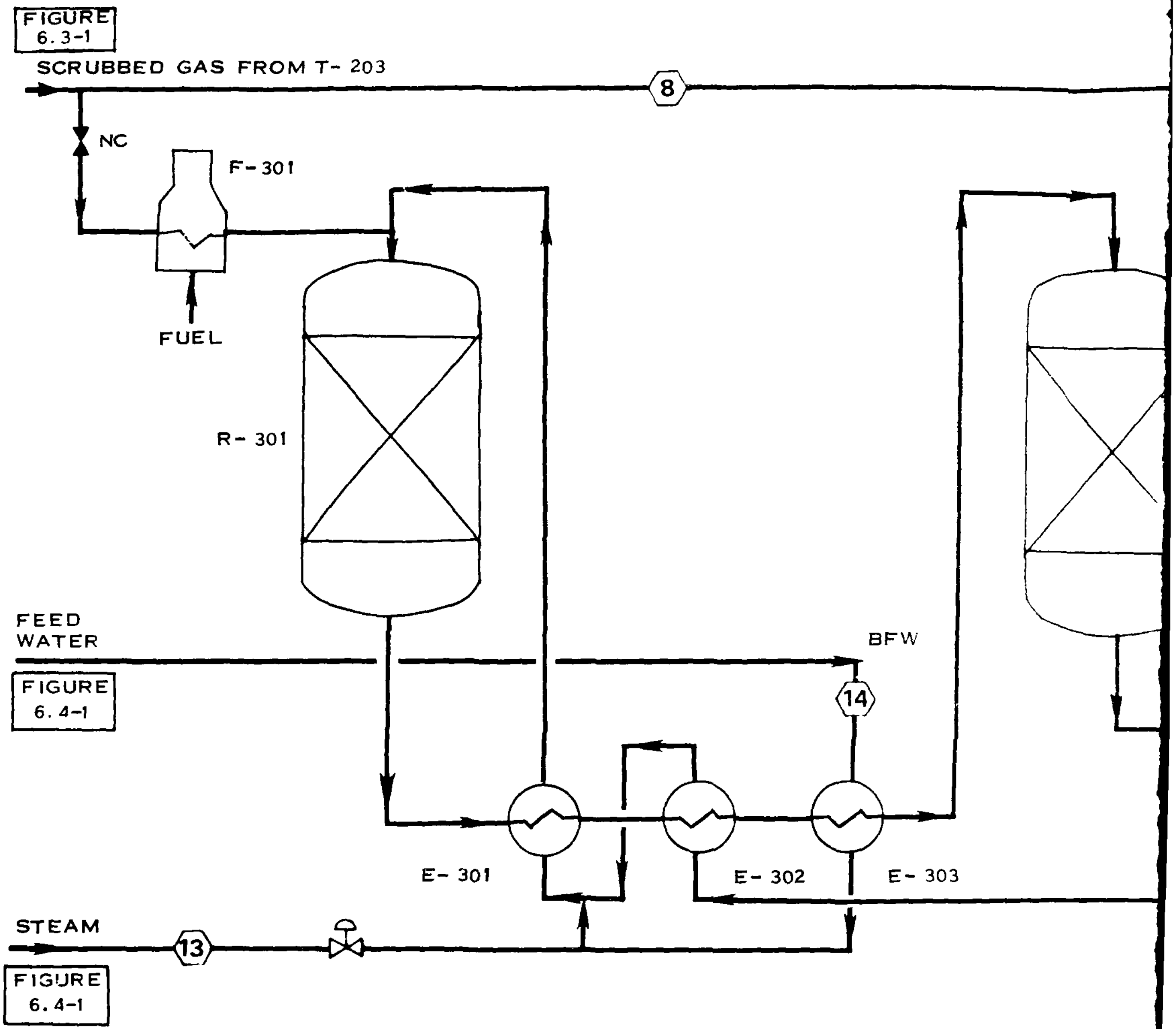
Multistage centrifugal compression (C-201) with interstage cooling is provided to increase the gas pressure. Condensate, consisting of hydrocarbons and water, produced in the water cooled interstage coolers is returned to the liquor collection tank in the cooling/cleaning area.

The compressed and cleaned gas leaving the section is washed with sulfuric acid in Ammonium Sulfate Saturator T-203 to remove ammonia not scrubbed out in the cooling and cleaning of the gas. The heat of this neutralization is removed by circulating the wash liquor through an external heat exchanger E-205. The ammonia-free gas exits to the CO Shift section.

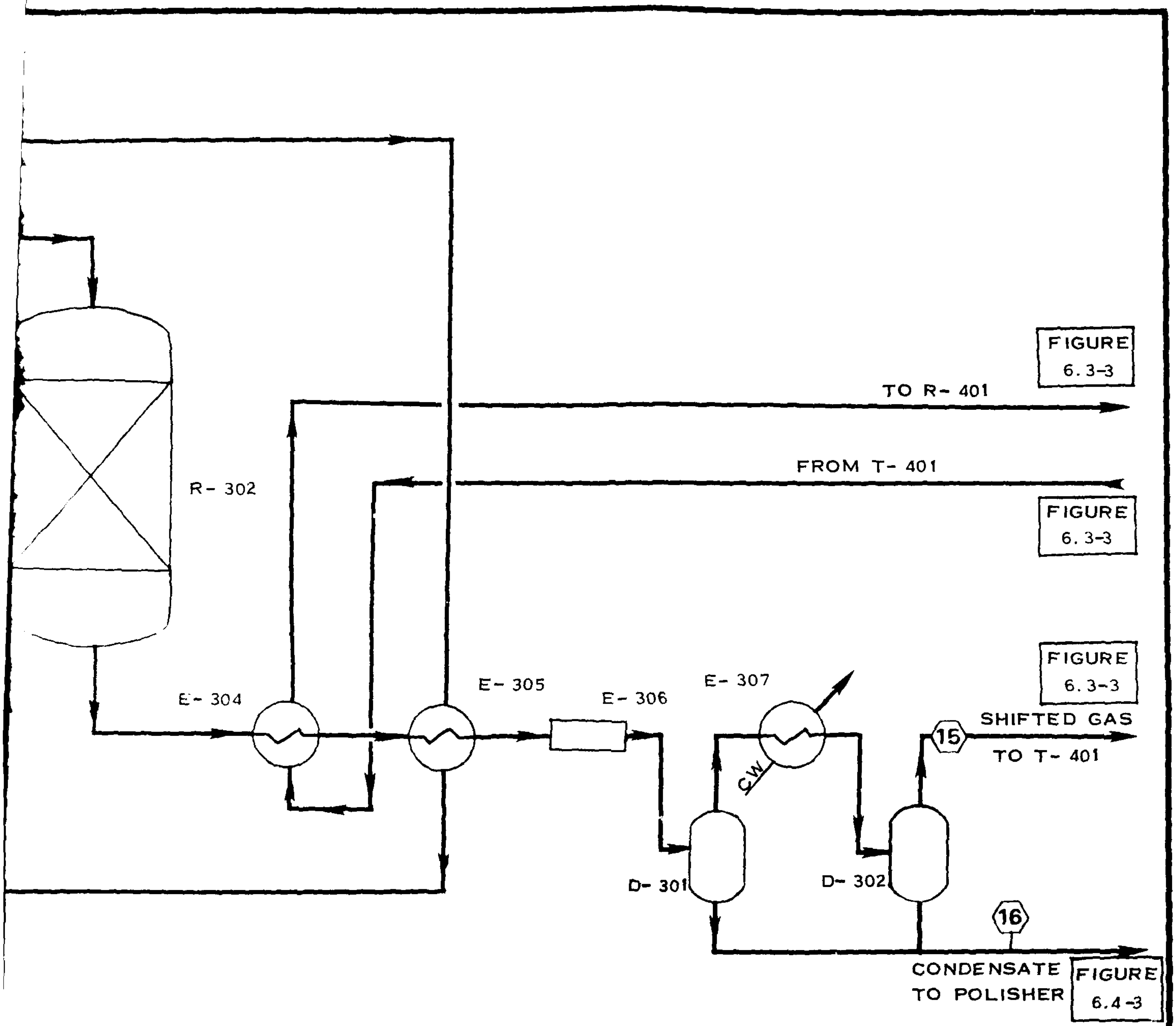
CO Shift

The CO Shift reaction is carried out in two stages. It is a highly exothermic reaction and the heat of reaction is used to preheat the feed to the first stage to raise steam and to preheat the clean gas before the final polishing.

The configuration of the CO Shift Section is shown in Figure 6.3-2 and the Mass Balance in Table 6.3-2. The temperature of scrubbed gas leaving the gas compression section is raised in preheaters E-305 and E-302 followed by direct injection of medium pressure steam. Upon further preheating with 1st shift effluent in heat exchanger E-301, the wet gas is introduced into the first stage reactor, R-301. After the reaction, the first stage effluent is cooled by heat exchange with the feed. Further heat recovery takes place by generation of medium pressure steam, and the cooled first stage effluent is introduced into the second stage of water gas shift reactor, R-302.



D-301	K.O. DRUM	E-305
D-302	TRIM COOLER K.O. DRUM	E-306
E-301	FEED/EFFLUENT HEAT EXCHANGER II	E-307
E-302	FEED/EFFLUENT HEAT EXCHANGER I	F-301
E-303	CO SHIFT STEAM GENERATOR	R-301
E-304	FUEL CELL FEED HEATER	R-302



E-305	FEED GAS PREHEATER
E-306	AIR COOLER
E-307	TRIM COOLER
F-301	START-UP HEATER
R-301	1ST CO SHIFT REACTOR
R-302	2ND CO SHIFT REACTOR

DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE
PROCESS FLOW DIAGRAM
CO SHIFT SECTION

FIGURE 6.3-2

EBASCO SERVICES INCORPORATED

TABLE 6.3-3

MASS BALANCE - CO SHIFT SECTION

Stream No.		8	13	14	15	16
Stream Name		Compressed Gas	Shift Steam	Boiler Feedwater	Shifted Gas	Condensate
Components	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016	336.50			775.30	
CO_2	44.010	131.80			571.30	
C_2H_4	28.032	2.40			2.40	
C_2H_6	30.048	3.50			3.50	
N_2	28.016	951.50			951.50	
CH_4	16.032	32.70			32.70	
CO	28.011	462.50			23.70	
H_2S	34.080	5.55			6.23	
COS	60.070	0.76			0.08	
NH_3	17.030	-			-	
HCN	27.030	0.32			0.32	
O_2	32.000					
Ar	39.948					
H_2O (Water)	18.016			88.80		674.22
H_2O (Steam)	18.016	11.0	1,044.90		31.00	
Total Flow	Lb Mol/Hr	1,938.58	1,044.90	88.80	2,398.03	674.22
Total Flow	Lb/Hr		18,825	1,600		12,147
Pressure	Psia	167	175	175	130	
Temperature	°F	100	371	237	120	120

The second stage shift operates at a temperature lower than the first, permitting further reaction of CO to generate more hydrogen and to reduce the CO content to the desired level.

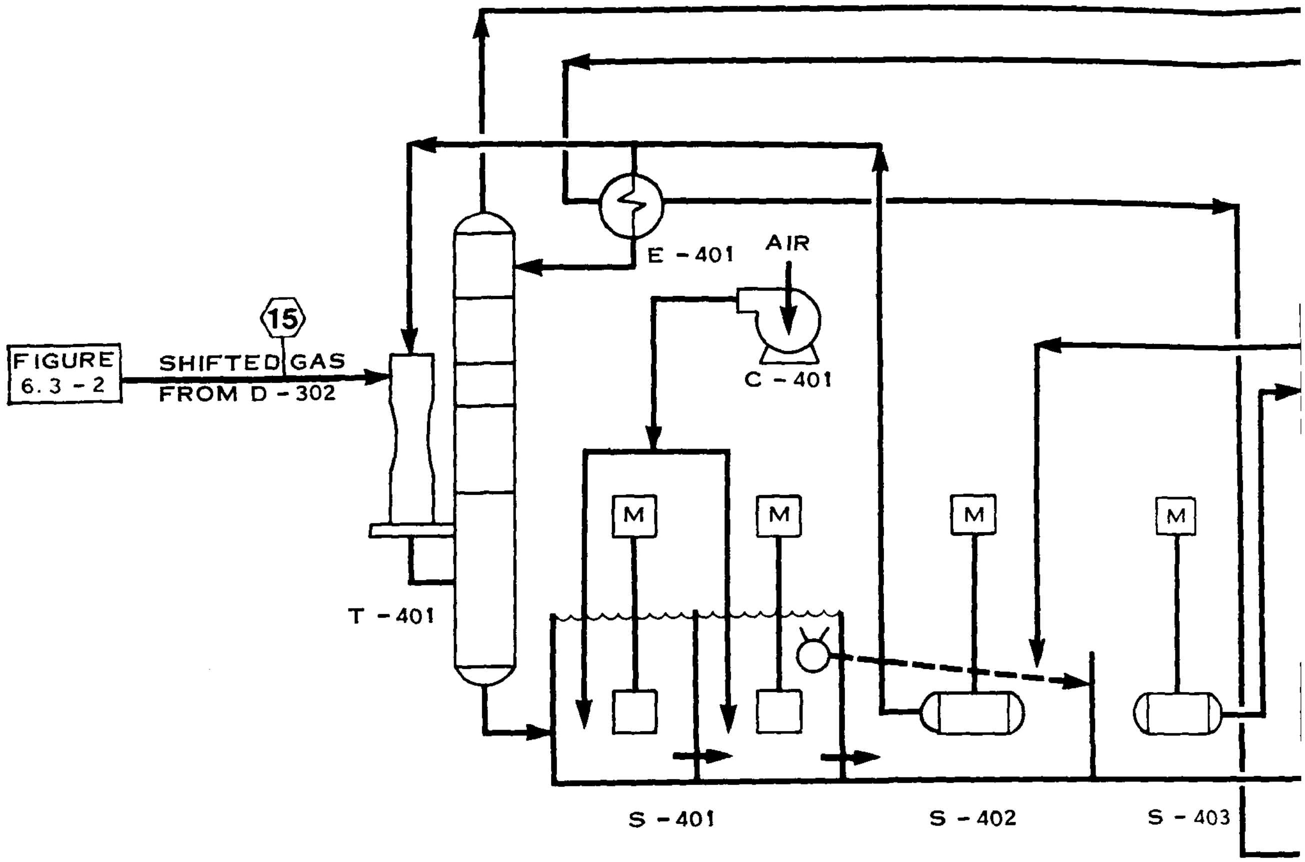
Second stage shift effluent is cooled by preheating anode feed gas in E-304 and preheating raw gas feed to the first stage shift. Additional cooling of the shifted gas to a temperature suitable for its introduction to the Desulfurization Section is accomplished by air and water cooling. Steam condensate resulting from gas cooling is sent to the Thermal Management System. During process startup, gas or oil fired heater, F-301 raises the temperature of the feed gas to the level required for the shift reaction.

Sulfur Removal and Recovery

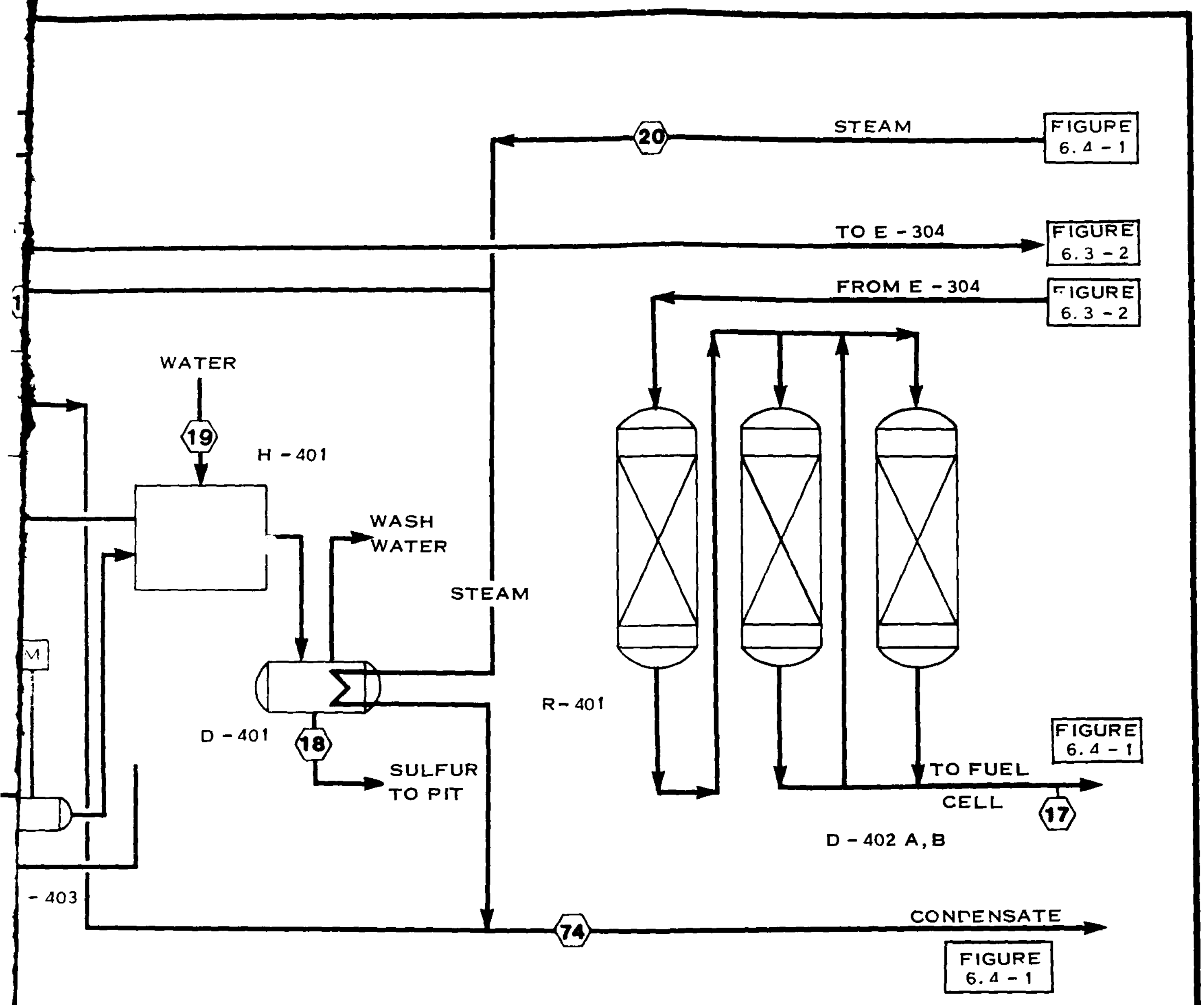
The Sulfur Removal and Recovery Section is shown in Figure 6.3-3 and the Mass Balance given in Table 6.3-4.

This section is designed to reduce the total sulfur content of the gas to 4 ppm, a level acceptable for the fuel cell operation and for compliance with the sulfur emission levels of the plant. A liquid phase oxidation Stretford Sulfur Removal Process is used for the removal of H_2S to the required level.

The shifted gas stream is directed to venturi contactor, T-401 which consists of a venturi type jet mixer and an absorber with an alkaline solution containing sodium vanadate. The H_2S is oxidized by the sodium vanadate to elemental sulfur and water. The solution is sent to oxidizer tank S-401 where by air spraying, and in the presence of anthraquinone disulfuric acid (ADA) the vanadium is oxidized regenerating the alkaline solution and the product sulfur is separated by flotation. The regenerated solution is sent to balance tank, S-402 and recycled to the absorber. The sulfur slurry, separated from the solution, flows to slurry tank S-403 and is separated from other chemicals by filtering and water washing. The sulfur is then reslurried with wash water and heated to the melting point. The molten sulfur flows from decanter, D-401 to the sulfur pit. Chemicals are returned to the system and the wash water discarded.



T - 401	VENTURI CONTACTOR
E - 401	SOLUTION HEATER
C - 401	AIR BLOWER
H - 401	SOLID SEPARATION WASH & RESLURRY
D - 401	SLURRY DECANTER
D - 402 A, B	ZnO DRUM
R - 401	HYDROLYSIS REACTOR
S - 401	OXIDIZER TANKS
S - 402	BALANCE TANK
S - 403	SLURRY TANK



DOA/GEORGETOWN UNIVERSITY

COAL GAS/FUEL CELL/COGENERATION

FORT HOOD, TEXAS SITE
PROCESS FLOW DIAGRAM
SULFUR REMOVAL AND
RECOVERY SECTION

FIGURE 6.3-3

EBASCO SERVICES INCORPORATED

TABLE 6.3-4

MASS BALANCE - SULFUR REMOVAL AND RECOVERY SECTION

Stream No.		15	17	18	19	20
Stream Name		Shifted Gas	Fuel Cell Fuel Gas	Sulfur Product	Wash Water	Steam to Sulfur Slurry
Components	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016	775.00	775.00			
CO_2	44.010	556.27	556.27			
C_2H_4	28.032	3.16	3.16			
C_2H_6	30.048	2.11	2.11			
N_2	28.016	796.58	796.58			
CH_4	16.032	28.95	28.95			
CO	28.011	21.76	21.76			
H_2S	34.080	5.72	0.00			
COS	60.070	0.07	0.004			
NH_3	17.030	-	-			
HCN	27.030	0.18	-			
O_2	32.000					
Ar	39.948					
H_2O (Water)	18.016					
H_2O (Steam)	18.016	28.52	28.46			
Total Flow	Lb Mol/Hr	2,218.32	2,212.30	5.7		
Flow Flow	Lb/Hr			182	2,261	540
Pressure	Psia	130	120			65
Temperature	°F	120	405			298

Product gas leaving the absorber is preheated to 405°F, the fuel cell temperature in the CO Shift Section before being returned to the Gas Desulfurization Section for final polishing.

The final polishing process protects the fuel cell power section from sulfur poisoning in the event of an upset in the sulfur removal plant. It also provides for the removal of residual COS and H_2S.

The preheated gas is put through a bed of low temperature catalyst in hydrolysis reactor, R-401 to convert COS to H_2S. The H_2S is then removed down to the required level by absorption in a zinc oxide bed. The final polished gas is then sent to the fuel cell anode.

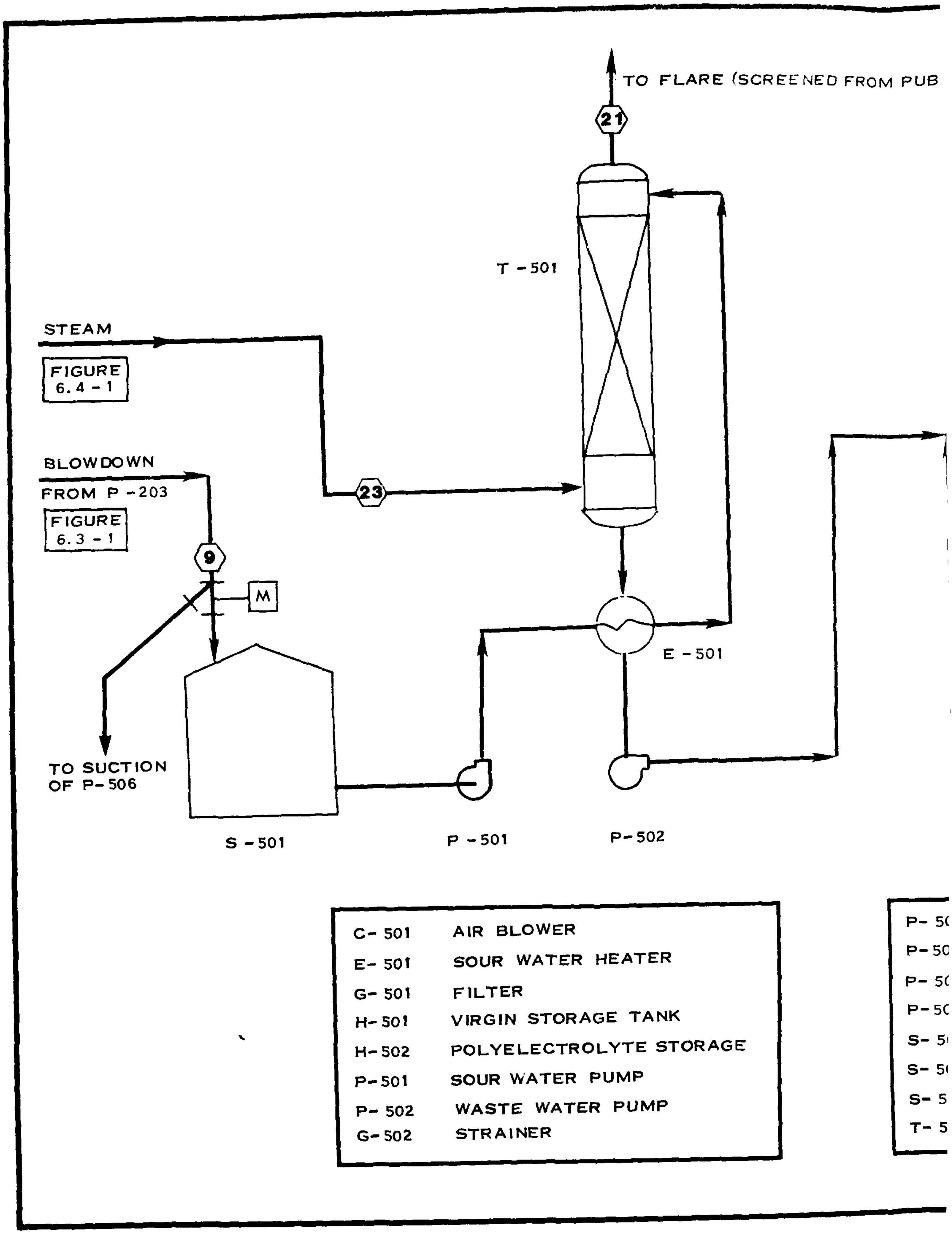
In the Stretford process, there is a by-product fixation of H_2S into thiosulfate[7]. To avoid the accumulation of thiosulfate and thiocyanate, the solution is purged by removing a slip stream which is sent off-site for disposal.

Process Condensate Treatment

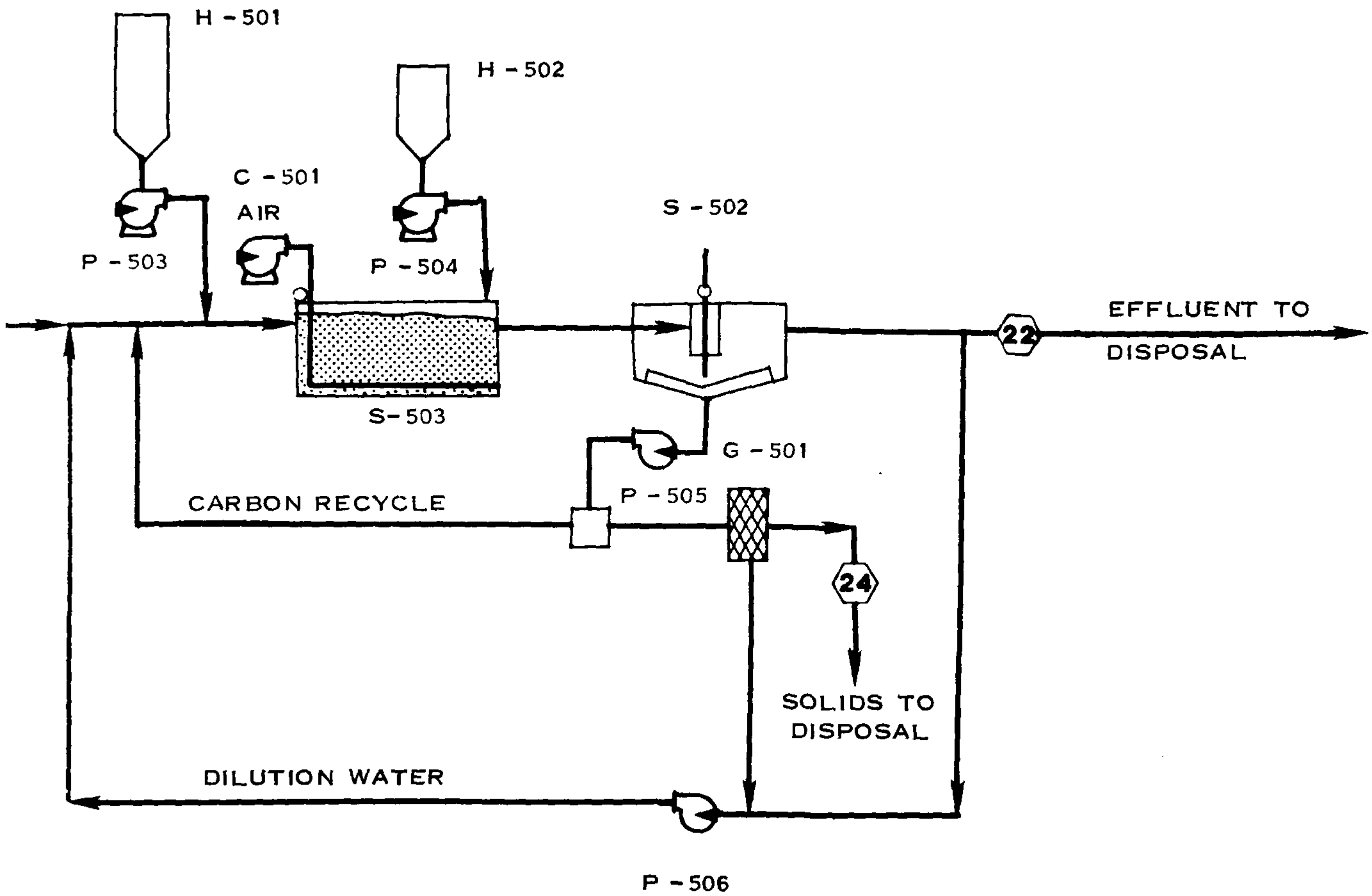
The Process Condensate Treatment Section is shown in Figure 6.3-4 and the mass balance given in Table 6.3-5.

Ammonia Stripping

Water containing sour gases (CO_2 and H_2S) is blown down from tar separator, D-204 of the Gas Cooling and Compression Section to sour water storage tank, S-501. It is then pumped to the Ammonia Stripper where ammonia and some phenols are removed by steam stripping. Steam consumption is reduced by heating incoming feed with stripper bottoms. Overhead vapors from the Ammonia Stripper are flared while stripper bottoms are sent to the Waste Water Treatment Sub-section for further processing.


TO FLARE (SCREENED FROM PUB
21
T -501
STEAM
FIGURE 6.4 - 1
BLOWDOWN
FROM P -203
FIGURE 6.3 - 1
23
9
M
E -501
TO SUCTION OF P-506
S -501
P -501
P-502
C-501 AIR BLOWER
E-501 SOUR WATER HEATER
G-501 FILTER
H-501 VIRGIN STORAGE TANK
H-502 POLYELECTROLYTE STORAGE
P-501 SOUR WATER PUMP
P-502 WASTE WATER PUMP
G-502 STRAINER

PUBLIC VIEW)



P- 503	VIRGIN CARBON FEED PUMP
P- 504	POLYELECTROLYTE STORAGE
P- 505	CARBON RECYCLE PUMP
P- 506	RECYCLE WATER PUMP
S- 501	SOUR WATER STORAGE TANK
S- 502	SETTLING TANK
S- 503	AERATION CONTACT TANK
T- 501	AMMONIA STRIPPER

DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE
PROCESS FLOW DIAGRAM
PROCESS CONDENSATE
TREATMENT SECTION

FIGURE 6.3-4

EBASCO SERVICES INCORPORATED

TABLE 6.3-5

MASS BALANCE - PROCESS CONDENSATE TREATMENT SECTION

Stream No.		9	21	22	23	24
Stream Name		Process Condensate Blowdown	Ammonia Flare Vent	Wastewater	Steam to Ammonia Stripper	Clarifier Waste
Components	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016					
CO_2	44.010	1.61	1.61			
C_2H_4	28.032					
C_2H_6	30.048					
N_2	28.016					
CH_4	16.032					
CO	18.011					
H_2S	34.080					
COS	60.070					
NH_3	17.030	0.78	0.70			
HCN	27.030					
O_2	32.000					
Ar	39.948					
H_2O (Water)	18.016	626.77	4.71	759.71	132.94	
H_2O (Steam)	18.016					
Total Flow	Lb Mol/Hr	629.16	7.02	759.71	132.94	
Total Flow	Lb/Hr	3820		13,687	2395	247
Solids	Lb/Hr					87
Pressure	Psia	17			40	
Temperature	°F	123			267	

Water Treatment

Water leaving Ammonia Stripping is further treated in the Waste Water Treatment subsection. A Powdered Activated Carbon Treatment (PACT) process is used to produce a waste water adequate for discharge. Raw water entering the system is first diluted by addition of recycled effluent water to adjust the concentration of toxic substances to the requirements of the biological treatment plant. Virgin carbon from H-501 storage tank is added to the diluted waste water as it flows into the aeration contact tank S-503. In the aeration tank the waste water is aerated in the presence of activated carbon, biomass, and inert ash. Mixed liquor dissolved oxygen level is maintained to insure optimum treatment.

To aid in solids settling, polymer from H-502 storage tank is added to the mixed liquor as it flows to the system clarifier S-502. In the clarifier, the solids are settled out. The clarifier overflow is split into two streams. A portion of the clarifier overflow is discharged for disposal. No further treatment of this effluent discharge is required. The remainder of the clarifier overflow is recycled for dilution of incoming feed.

Clarifier underflow solids are continuously recycled to the aeration tank to maintain the high mixed liquor solids concentration. Spent carbor and biomass from the clarifier underflow are filtered before disposal. Filtrate water is combined with effluent recycle for dilution of feed.

6.3.3 System Performance

Each plant section is expected to meet or exceed the system availability given in paragraph 2.4 due to the following:

- The technologies used are commercially proven.
- Equipment is selected to provide continuous operation with minimum operator attention and minimum maintenance.

- The design guidelines which are used in the design of each section assure continuous, safe operation. The CO Shift Section performance is based on end of run conditions, where the performance of the catalyst is at its lowest point. But at start of run, when the bed operates with fresh catalyst, the optimum operating conditions can be maintained at lower temperatures, with lower steam consumption.

  The sulfur removal plant can remove all H_2S in the gas resulting from a coal with higher than design sulfur content by increasing the Stretford solution flowrate.

- The availability of the system is increased by providing installed spares for all the pumps in the process.

The electrostatic precipitator (ESP) used for the gas cleaning is the equipment with the highest potential of unscheduled shut-down. It is estimated that in addition to the annual maintenance, the ESP may have four days of unscheduled shut-downs, equivalent to an availability of 95%.

The performance of the Gas Processing System under part load conditions can be assessed as satisfactory. Variations in the gas flow rate greater than 50% turndown can be handled with no adverse effect on product quality, but with some reduction in plant efficiency for reasons indicated below.

The gas cooling and cleaning is achieved by scrubbing with liquids. In order to maintain scrubbing effectiveness, the liquid circulation flow rate and corresponding pumping power must be sustained even though the gas flow rate is reduced.

To prevent destructive gas surging at low flows, the centrifugal compressors must bypass gas from their discharges to their inlets, increasing the compression horsepower per unit of gas processed. The extent of the increase in specific power consumption depends on the compressor selected and will be evaluated during the detail design phase.

The CO shift reactors can accept a turndown below 50% in the gas flow rate. Although the conversion rate improves with reduced space velocity it becomes more difficult to reach the design reaction temperature because reduced gas flow makes less reaction heat available for preheating the feed gas.

The Stretford process has a high degree of flexibility in that it can tolerate wide variations in both gas feed rate as well as H_2S concentration, especially, when using a venturi contactor (7) without negative impact on the energy consumption, or plant performance.

The ammonia stripping process in the Process Condensate Treating Section requires good contact between the waste water and the live steam. If the liquid flow rate is reduced by more than 30% or more the ammonia stripper can be operated intermittently at full rate, using waste water collected in the Sour Water Storage Tank.

The PACT waste water treatment system also has a high degree of flexibility and can accommodate wide variations in the composition and flow rate of the feed.[8] The addition of dilution water gives the system the ability to adjust the composition of the waste water feed to the requirements of the PACT process.

6.3.4 Maintenance

Equipment constituting the Gas Processing Section is selected and applied for maximum reliability which is sustained by a preventative maintenance program. Typical maintenance procedures most of which are applied during the annual scheduled shutdown, are as follows:

Replacement or repacking of bearings
Replacement or cleaning of spray nozzles
Filter and strainer replacement
Alignment of equipment
Vibration tests and rebalancing of rotating apparatus if required
Replacement of broken electrode wires or damaged collector plates of the electrostatic precipitators

Valve and steam trap servicing
Testing, adjusting, recalibrating and/or replacement of instrumentation and controls
Tank and vessel cleaning
Retubing of heat exchangers
Replacement of tower packing
Changeout of catalysts, etc.

6.3.5 Technical Risks

The assessment of technical risks associated with this part of the plant indicates that the overall technical risks may be considered low.

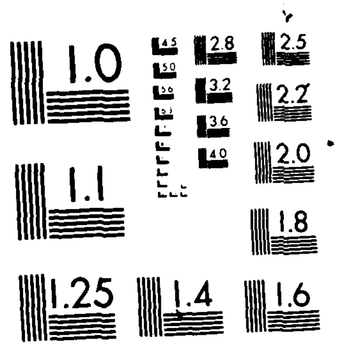
The equipment and processes used for Gas Cooling and Cleaning have been used in the coke oven industry in similar applications. Additionally, there are Wellman-Galusha gasification plants in operation which currently use the spray cooling and electrostatic precipitators included in the design of this plant [1]. The venturi scrubber used for final cooling and cleaning of the gas is of the type used in existing Texaco coal gasification plants.

The gas compressor can be subject to corrosion and erosion from gas constituents. During detailed design, consideration will be given to avoiding condensation in the compressor and to the selection of suitable materials of construction.

The CO Shift section is not considered to be a high risk, as far as equipment failure and performance are concerned. The COMO sulfur tolerant catalyst, has been used successfully in the chemical industry. Currently there are two Texaco coal gasification projects (TVA and Texas-Eastman) which are using the catalyst without any indication of deterioration. The process conditions do not pose any fabrication problems, comparably sized equipment operating at similar pressures being relatively common. The economic risks associated with the catalyst utilization are not considered high, as failure would occur as a gradual reduction of activity as opposed to catastrophic failure or total inoperability. Risk would reduce the potential for the additional cost of recharging the reactors at greater frequency than expected.

AD-A173 690 FEASIBILITY STUDY OF COAL GASIFICATION/FUEL CELL/COGENERATION PROJECT FOR..(U) EBASCO SERVICES INC NEW YORK B ROSSI ET AL. JUL 85 DAAG29-85-C-0007 2/3

UNCLASSIFIED F/G 10/2 NL



MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

Although not used extensively in coal gasification plants, the Stretford process has been used successfully in the petrochemical industry.[7] The process uses relatively simple equipment items such as a venturi scrubber and circulating pumps, which will be provided with installed spares to minimize process disruptions due to possible equipment failure. Reports from operating Stretford plants have in some cases indicated higher chemical consumption than anticipated. Although the reagents used are expensive, the cost of potentially increased consumption is small in terms of overall operating costs for this Section.

The front end process of the condensate treatment section is an Ammonia Stripping unit. Ammonia stripping is a well established process where the variations of ammonia concentration in waste water are controlled by adjusting the steam injection.

The PACT process used in the process condensate treatment is a new advanced biophysical treatment system, which is not yet fully commercialized. Extensive testing of coal gasification waste water was performed in pilot plant operations. Ammonia stripping and phenol extraction failure tests have confirmed that the PACT process provides continuous, reliable treatment, resistant to synfuels facility process upset. Experience has shown that following each organic stress test, the PACT process returned to optimum operation within 2 to 4 days.

By providing excess capacity in the activated carbon feeding system and increased contact time in the aeration tank, the PACT system can be designed to overcome the risks of process upsets.

During startup, the entire system is warmed by circulation of compressed nitrogen. The UTC reformer package can be made operational from the cold standby mode in about 4 hours[9] if the rest of the system is hot. A complete changeover from coal gas to natural gas feed will make the fuel cell system operational in 6 to 8 hours.

6.3.6 Natural Gas Standby

The installation of facilities to provide natural gas standby service to mitigate the effects of a failure of the coal supply or an unexpected shutdown of the Coal Gasification Section is under consideration.

UTC has designed, manufactured and operated steam reforming units for their 4.8-MW fuel cells. A description of the unit is given in this section.

Natural gas supply is available at 20 psig. The gas must be compressed to 185 psig to allow for pressure drop through the plant for delivery at 105 psig, to the fuel cell anode.

The UTC steam reforming package includes a hydrodesulfurizer, where the sulfur compounds in the gas are converted catalytically to H_2S and a ZnO bed where trace amounts of H_2S are absorbed. This desulfurizing step is necessary for the protection of the reforming catalyst against sulfur poisoning.

The steam reformer consists of a pressure vessel containing vertical tubes where the reaction takes place over the catalyst at about 1800°F. Prior to entering the steam reformer, steam and the desulfurized gas is mixed in a 3.7:1 ratio. The endothermic reaction is sustained by heat generated in the upper dome of the vessel by burning depleted anode gas with pressurized air or alternately by diverting a stream of natural gas for combustion in the reformer. The hot exhaust gas from the burner flows over and heats the catalyst filled tubes and is then used in an expander to drive the combustion air compressor.

The reformed methane stream contains H_2, CO, CO_2, some unreacted CH_4 and water. To obtain the H_2 and CO concentrations as specified for the anode feed gas, a CO Shift reaction is required for the conversion of CO to H_2, followed by cooling of the gas and removal of condensate. Suitability of the CO Shift Section designed for coal gas processing for dual use with natural gas reformer effluent, must be reviewed during the detailed design phase.

6.3.7 References

6.3-1 Gas Engineers Handbook, The Industrial Press, 1965

6.3-2 Kinetics Technology International Corporation, "Site-Specific Assessment of a 150-MW Coal Gasification Fuel Cell Power Plant" EPRI EM-3162, November 1983

6.3-3 Kinetics Technology International Corporation, "Assessment of a Coal Gasification Fuel Cell System for Utility Application" EPRI EM-2387, May 1982

6.3-4 C F Braun & Co, "Assessment of Sulfur Removal Processes for Advanced Fuel Cell Systems" EPRI EM-1333, January 1980

6.3-5 Wellman-Galusha Gas Producers, Dravo

6.3-6 Personal Communication with Dravo Engineers, Inc.

6.3-7 Personal Communication with the Ralph M Parsons Co.

6.3-8 Personal Communication with Zimpro, Inc.

6.3-9 Personal Communication with UTC.

6.4 FUEL CELL AND POWER CONDITIONER

6.4.1 Fuel Cell System

6.4.1.1 Functions and Design Requirements

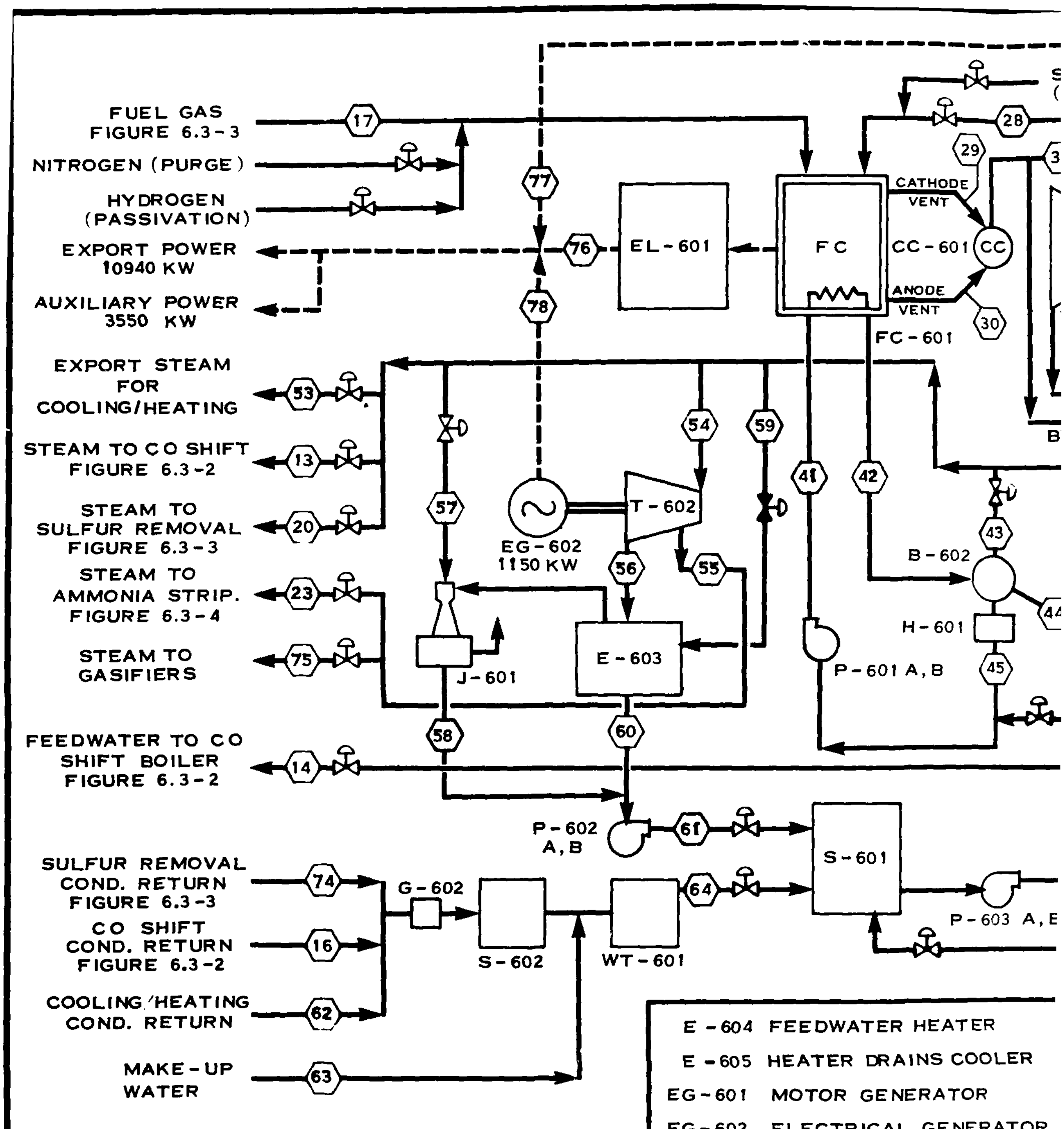
The function of the fuel cell system is to take the hydrogen rich gas stream from the gas processing section, and to convert the energy value of this fuel into useable electric, mechanical and thermal energy. The fuel cell system consists of the fuel cell stacks, catalytic combustor, turbo-expander, compressor and motor-generator.

DC power is produced in the fuel cell by the electrochemical reaction of the hydrogen in the gas stream with the oxygen in the compressed air supply. Unregulated DC power is sent to the power conditioner where it is converted to three phase, 60 Hz AC power suitable for connection to the utility grid. Byproduct heat from the fuel cell is removed by a cooling system and utilized in the thermal management system. Energy remaining in the fuel cell vent gases is extracted by a catalytic combustor and an expander turbine. The turbine drives both the compressor supplying air to the fuel cell cathode and a generator.

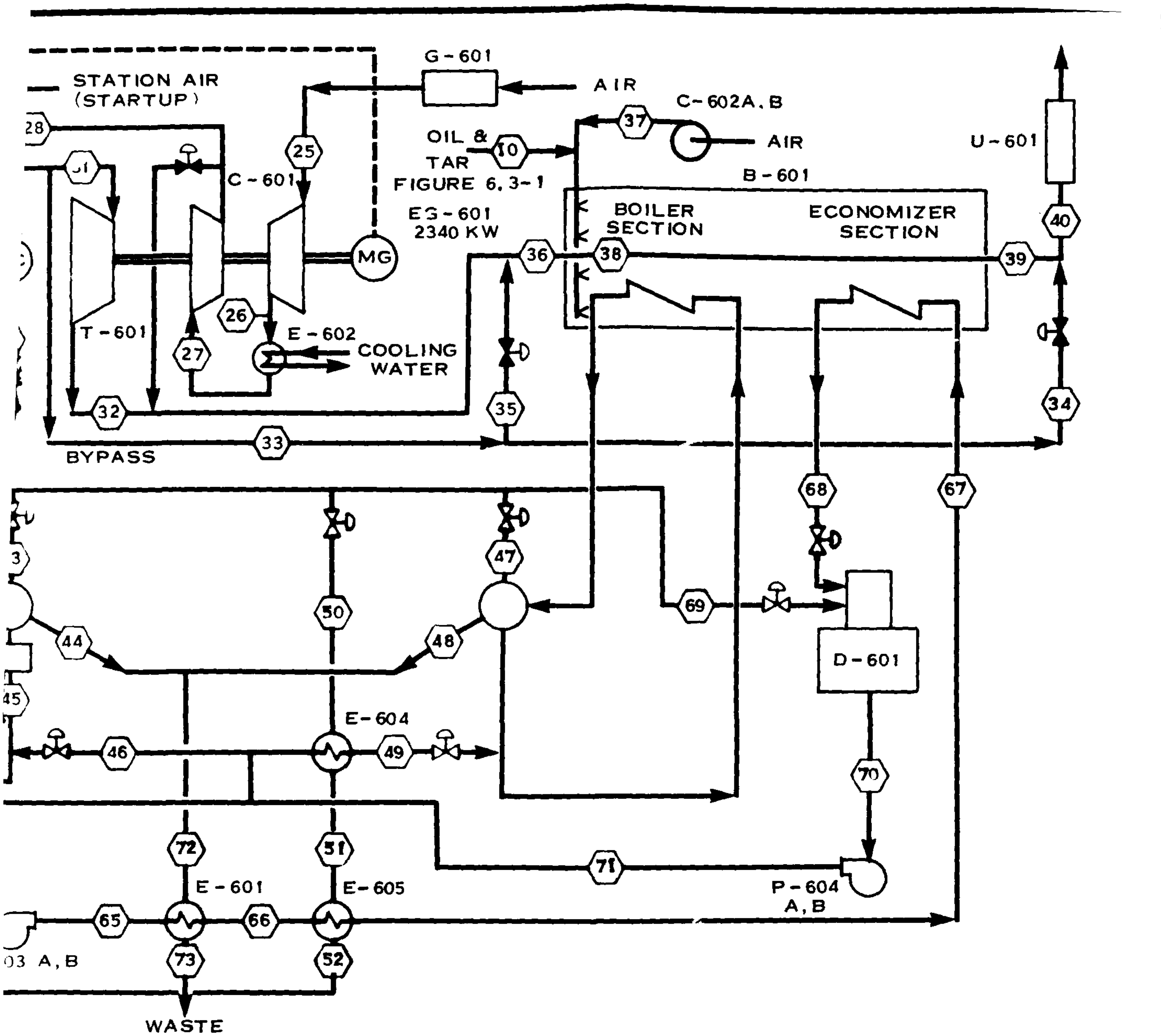
A flow diagram of the system is shown in Figure 6.4-1.

Criteria for the fuel cell is as follows:

- The fuel cell is a phosphoric acid type of modular design, manufactured by United Technologies Corporation
- Gross DC output is 11.6 MW under design conditions
- Electrical conversion efficiency averages 55% over the design life.
- Fuel cell stacks are replaceable and have a 40,000 hour design life
- Oxygen is supplied to the fuel cell by compressed air
- Fuel cell is water cooled and the byproduct heat recovered
- The fuel cell is capable of operating over a range of 50 to 100 percent of design DC power output
- The fuel cell vent gas effluent meets all federal and local environmental pollution standards.



B-601	HEAT RECOVERY STEAM GENERATOR
B-602	FC STEAM GENERATOR
C-601	AIR COMPRESSOR
CC-601	CATALYTIC COMBUSTOR
C-602	HRSG BURNER AIR FAN
D-601	DEAERATING HEATER
E-601	BLOWDOWN HEAT EXCHANGER
E-602	AIR COMPRESSOR INTERCOOLER
E-603	STEAM CONDENSER
E-604	FEEDWATER HEATER
E-605	HEATER DRAINS COOLER
EG-601	MOTOR GENERATOR
EG-602	ELECTRICAL GENERATOR
EL-601	POWER CONDITIONER
FC-601	FUEL CELL
G-601	AIR FILTER/SILENCER
G-602	FILTER
H-601	START-UP ELECTRIC HE
J-601	STEAM JET AIR EJECTOR



R	P-601	CIRCULATING PUMP
LER	P-602	CONDENSATE PUMP
	P-603	MAKE-UP WATER PUMP
ATOR	P-604	FEEDWATER PUMP
R	S-601	CONDENSATE STORAGE TANK
	S-602	CONDENSATE PROVER TANK
ER	T-601	GAS EXPANDER
	T-602	STEAM TURBINE
C HEATER	U-601	VENT STACK
CTOR	WT-601	MAKE-UP DEMINERALIZER

DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT HOOD TEXAS SITE
PROCESS FLOW DIAGRAM
UTC FUEL CELL AND
THERMAL MANAGEMENT SYSTEMS

FIGURE 6.4 - 1

EBASCO SERVICES INCORPORATED

Fuel cell performance is dependent on the characteristics of the hydrogen rich anode gas. Anode gas must meet pressure and temperature criteria set by the fuel cell manufacturer, and the purity requirements of Table 6.4-1.

Fuel cell cooling water chemistry is important to prevent corrosion, fouling and blockage of the cooling channels in the fuel cell. Cooling water criteria is shown in Table 6.4-2.

6.4.1.2 System Description

The fuel cell system mass balance is given in Table 6.4-3. Fuel cell parameters are shown in Table 6.4-4. The fuel cell must be purchased from one of the two fuel cell manufacturers with designs near commercialization. The design and configuration of the fuel cell for the Georgetown site will conform to the UTC design(1).

The fuel cell anode receives hydrogen rich gas from the gas processing system. At the design power output of 11.6 MWe DC, the anode of the fuel cell requires 775 lb moles of hydrogen per hour. This results in an anode gas flow of aproximately 50,000 lbs/hr of which 35% is hydrogen. The fuel cell utilizes 85% of the hydrogen fuel and discharges the remaining hydrogen along with the carrier gas from the anode vent. No gas other than hydrogen undergoes a reaction at the anode.

TABLE 6.4-1

ANODE FEED GAS SPECIFICATION

COMPONENT	LIMIT[1]
H_2	32% min[3]
CO	2% max
Olefins	1000 ppm max
Higher Hydrocarbons	1000 ppm max
NH_3	0.5 ppm max
Cl_2	0.5 ppm max
H_2S + COS	5 ppm max
Tars/Oils	.05 ppm max (by wt)
Metal ions	1 ppm max (by wt)
Particulates	30 ug/m^3 max
Pressure	120 psia
Temperature [2]	405°F
H_2 Flow	775 lb moles/hr

Notes:

1. By volume unless otherwise noted
2. Design temperature of cell
3. Design basis. Lower values may be acceptable but will penalize cell performance

TABLE 6.4-2

FUEL CELL COOLING WATER CRITERIA

Parameter	Limit
Suspended Solids	1 ppm
SiO_2	0.3 ppm
pH	5.0 - 7.0
Conductivity	10 micromho/cm

TABLE 6.4-3

MASS BALANCE - FUEL CELL SECTION

Stream No.		17	25	26	27	28
Stream Name		Anode Feed (Fuel Gas)	Ambient Air Inlet	Stage Comp. Exhaust	Intercooler Exhaust	Cathode Feed (Air)
		Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
Components	MW					
H_2	2.016	775.0				
CO_2	44.010	556.27				
C_2H_4	28.032	3.16				
C_2H_6	30.048	2.11				
N_2	28.016	796.58	1,822.30	1,822.30	1,822.30	1,822.30
CH_4	16.032	28.95				
CO	18.011	21.76				
H_2S	34.080	0.0011				
COS	60.070	0.009				
NH_3	17.030					
HCN	27.030					
O_2	32.000		488.00	488.00	488.00	488.00
Ar	39.948		23.58	23.58	23.58	23.58
H_2O (Water)	18.016	28.46	23.58	23.58	23.58	23.58
H_2O (Steam)	18.016					
Total Flow	Lb Mol/Hr	2,212.30	2,357.46	2,357.46	2,357.46	2,357.46
Total Flow	Lb/Hr	50,099	68,036	68,036	68,036	68,036
Pressure	Psia	120	14.7	40	40	118
Temperature	°F	405	60	289	95	361

TABLE 6.4-3 (Cont'd)

Stream No.		29	30	31	32
Stream Name		Cathode Exhaust	Anode Exhaust	Combustor Exhaust	Expander Exhaust
		Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
Components	MW				
H_2	2.016		116.25		
CO_2	44.010		556.21	617.52	617.50
C_2H_4	28.032		3.16		
C_2H_6	30.048		2.11		
N_2	28.016	1,822.30	796.58	2,618.88	2,618.88
CH_4	16.032		28.95		
CO	28.011		21.76		
H_2S	34.080		0.0011		
COS	60.070		0.009		
NH_3	17.030				
HCN	27.030				
O_2	32.000	158.63		14.86	14.86
Ar	39.948	23.58		23.58	23.58
H_2O (Water)	18.016				
H_2O (Steam)	18.016	682.33	28.46	897.59	897.59
Total Flow	Lb Mol/Hr	2,686.84	1,553.55	4,172.43	4,172.44
Total Flow	Lb/Hr	69,365	48,771	118,136	118,136
Pressure	Psia	115	115	115	16.5
Temperature	°F	405	405	1,201	705

7774A

TABLE 6.4-4

FUEL CELL PARAMETERS

Parameter	Ft Hood Fuel Cell
No. of Fuel Cell Stacks	18
Stack Size	6' dia x 11' 6"
Overall skid ht. (Fuel Cell Skid Only)	16'
Arrangement	3 linear groups of 6 stacks, 3 stacks per skid
Cell Voltage (DC)	.68V
Electrical Conversion Efficiency	55%
Line Voltage (DC)	2100V
Power Output (gross DC)	11.6MWe
Cell Operating Temp/Pres	405°F/120 psia
Design Stack Life	40,000 hours
Fuel (Anode) Input (H_2)	775 lb moles/hr
Anode Mass Flow Inlet	50,099 lbs/hr
Anode Inlet Temp	405°F
Anode Inlet Pressure	120 psia
Anode Exhaust Temp/Pres	405°F/115 psia
H_2 Utilization	85%
Cathode Inlet Flow	488 lb moles O_2/hr 68,036 lbs air/hr
Cathode Inlet Temp/Pres	361°F/118 psia
Cathode Outlet Temp/Pres	405°F/115 psia

TABLE 6.4-4 (Cont'd)

Parameter	Georgetown Fuel Cell
O_2 utilization	70%
Coolant type	water/steam
Coolant flow	1.67×10^5 lbs/hr
Inlet Temp/Pres	370°F/250 psia
Outlet Temp/Pres	397°F/240 psia (2 phase)
Heat rejected to coolant	28.7×10^6 Btu/hr

Hydrogen molecules that react at the anode, give up two electrons to form two hydrogen ions. These ions migrate through the phosphoric acid electrolyte to the cathode, where they react with oxygen to form water. Oxygen is supplied to the cathode in the form of compressed air. Approximately 68,000 lbs of air flows to the fuel cell cathode. Seventy percent of the oxygen in the air is utilized in the fuel cell. The oxygen depleted air carrying water vapor formed in the fuel cell, exits at the cathode exhaust.

The efficiency and performance of the fuel cell is highly dependent upon the operating pressure and temperature. The manufacturer, UTC, has designed the fuel cell to operate at 120 psia and 405°F. The pressure of the anode gas is maintained by the gas processing section. The temperature of the fuel cell is maintained by cooling water, which carries off the heat generated in the fuel cell by the exothermic reaction of hydrogen. Under design conditions, 28.7 x 10^6 Btu/hr of heat is rejected to the cooling water which circulates between cell plates. The cooling water boils in the cell stack assemblies, exiting as a saturated steam/water mixture at 240 psia. The steam is utilized in the thermal management system. Cooling water flow is 380 gpm.

The fuel cell consists of 18 cell stack assemblies. Each cell stack assembly contains 500 individual cells with an active surface area of 10.6 ft^2 each. The cell stack assembly is housed in a pressure vessel that includes insulation, freeze protection electrical heater and hydrogen leak detection instrumentation. The cell stack assemblies come skid mounted in a group of 3 with prefabricated piping for fuel, air and coolant. The cell stack assemblies are arranged in three linear groups of six. Each group of six stacks is electrically connected in series and the three parallel trains are connected to the electrical protection unit of the power conditioner.

Gases exit the anode containing about 7% unreacted hydrogen along with small amounts of other hydrocarbons that were formed in the coal gasification process. The heat value of these gases is recovered by combining with the cathode exhaust and burning in a catalytic combustor. The combustor consists of a pressure vessel with a mixing manifold, a gaseous mixing chamber and a length of Pt/Pd catalyst on a ceramic or metal matrix.

A catalytic combustor was chosen because it can burn trace quantities of combustible gases without concern for flame propagation. An alternative design would be to use a flame burner, but natural gas or other fuel would have to be added to maintain the burner flame.

Under design conditions, 27.9 million Btu/hr is released in the combustor, raising the exit gas temperature to 1201°F. The hot gases are expanded in a turbo-expander which drives both the cathode air compressor and a generator. By expanding the gases from 115 psia to 16.5 psia, the expander develops 6698 shaft horsepower which is sufficient to drive the compressor and a 2.46 MW induction generator. After exiting the expander, the gas stream goes to a heat recovery steam generator (see paragraph 6.5) before venting to the atmosphere. This configuration maximizes the mechanical and electrical energy recovered from the fuel cell vent gases.

The vent gases are the only environmental emissions from the fuel cell system. Pollutants consist of SO_2, NO_x and particulates formed in the catalytic combustor. These pollutants are minimized due to the extensive sulfur scrubbing in the gas processing system and the relatively low temperature in the catalytic combustor compared to normal gas fired turbine plants. The quantity of pollutants in the vent gases are shown in Table 7-1.

Oxygen is supplied to the fuel cell cathode by a two stage water cooled air compressor that is driven by the expander-turbine. The compressor delivers 14,967 scfm of compressed air to the cell and requires 3,217 shaft horsepower.

6.4.1.3 Performance

The basic performance parameters of the fuel cell system are dc current, dc voltage and reactant utilization. Under design conditions, a supply of 775 lb-moles/hr of hydrogen and 488 moles of oxygen will produce 5520 amps at a pallet (6 stack assemblies) voltage of 2100 volts. These parameters will vary with the load and the age of the cell stacks.

The cell voltage, and hence the electrical conversion efficiency, will vary with the age of the cell stack due to contamination of the electrodes. Voltage will decrease slightly more than 10% over the 40,000 hour design life of the cell. The fuel cell will normally be base loaded, but it can operate at any load between 50% and 100% of design. As load decreases, cell current density decreases and thereby increases the cell efficiency (voltage). Reactant utilization also is a function of both voltage and load. Reactant utilization decreases with load reduction, but this makes the cell stack operate more efficiently since the last cell experiences a richer gas stream. The hydrogen utilization does not change significantly with load, partly because an anode recycle blower provides a feedback mechanism. Oxygen utilization does change significantly with load. The fuel cell stacks will operate at approximately a 10% greater efficiency at 50% load than at 100% load.

Figure 6.4-2 shows the relationship between pallet voltage and dc current.

6.4.1.4 Maintenance

Maintenance for the turbocompressor and generator is standard for rotating equipment with emphasis on periodic check and or replacement of bearings, lubricant, and seals.

Maintenance for the fuel cell stack, centers on replacement of the stack due to degradation of the electrodes. Replacement can be based on a set schedule of operation hours or when stack voltage drops below a minimum set point. The entire stack pressure vessel would be replaced and returned to the manufacturer. The catalyst bed in the catalytic combustor must also be periodically replaced.

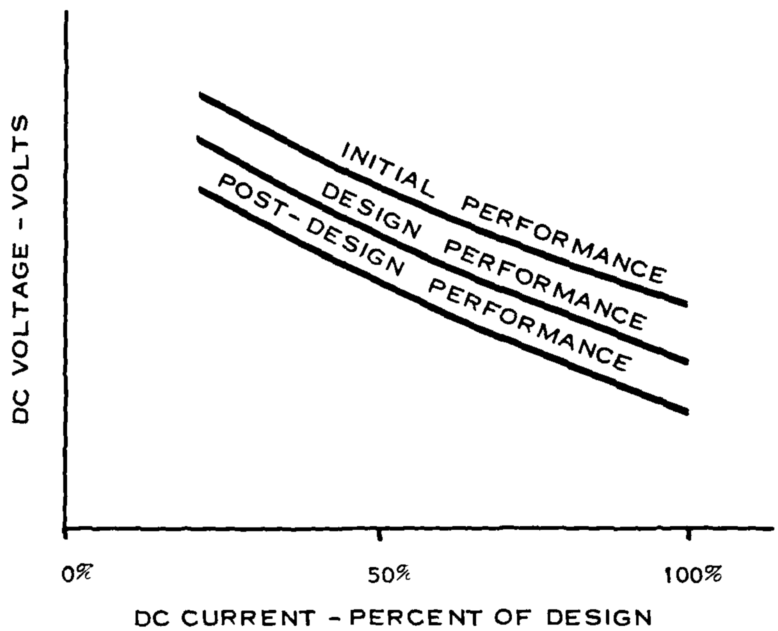


FIGURE 6.4-2 EFFECT OF OPERATING TIME ON DC VOLTAGE

Operation and maintenance experience for fuel cells comes from laboratory testing, the ongoing program of field testing small 40 kW on-site fuel cells, and the 4.5 MWe demonstration plant now in operation in Tokyo. The years of laboratory tests indicate that the fuel cell stack will meet the 40,000 hours design life, and the 40 kW program now in its third year has incurred no significant maintenance problems. The Tokyo Electric Power Company (TEPCO) facility has been running since February 1984, and as of March 1985 has accumulated more than 4,500,000 kW-hours of operation. None of the operational and maintenance problems experienced so far by TEPCO have involved the fuel cell stacks. A fuel cell demonstration plant built by Con Edison in New York experienced failure of the fuel cell stacks due to electrolyte leakage while in storage for 3 years. The design of the cell stacks has been improved since the Con Ed stacks were manufactured, and no leakage has been experienced with either the TEPCO stacks or a TVA experimental stack.

6.4.1.5 Technical Risks

Certain technical risks are inherent with the fuel cell since it is not a fully commercialized technology and operating experience is limited. The technical risk is that the fuel cell could fail to perform as specified due to:

- electrolyte leakage
- low cell voltage or voltage fluctuations
- catalyst poisoning
- coolant fouling

The first two risks can be reduced only by the cell design which in turn depends on the quality of the UTC testing and development program, and the feedback from the TEPCO facility.

The plant designer can minimize the risks due to catalyst poisoning and coolant fouling by providing clean anode gas and cooling water. The anode gas clean-up provides for state of the art sulfur removal despite the fact that recent laboratory experience has indicated that this specification could be relaxed.(2) The cooling water specification is more restrictive than originally called for by UTC, based on experience from TEPCO.

6.4.2 Power Conditioner

6.4.2.1 Functions and Design Requirements

The power conditioner is used to convert the dc output from the fuel cell to 3-phase, ac, 60 Hz, for interconnection with the TP&L system. It also regulates the operation of the fuel cell so as to maintain the required power output. A functional block diagram of a power conditioner is shown in Figure 6.4-3. The key component is the inverter which performs the conversion, maintains synchronization with the TP&L system and minimizes the generation of harmonics. The power conditioner also contains various safety elements to protect the fuel cell from abnormal voltage conditions and the conditioner itself from upset conditions.

The power conditioner and fuel cell design are linked and should be from the same vendor. The power conditioner is custom designed by UTC and described in Reference 6.4-1. The system offers modular design and electrical characteristics such that it is compatible with a single 11.6 MW fuel cell. Design criteria for the power conditioner includes:

- The conditioner is rated to have an output of 11 MW ac.

- The conditioner is capable of operation over a range of 30% to 100% of design power output.

- Dc to ac conversion efficiency exceeds 90% over the entire operating range, and 95% under design conditions.

- The conditioner is capable of controlling both real and reactive power

- Ac output conforms to TP&L requiments

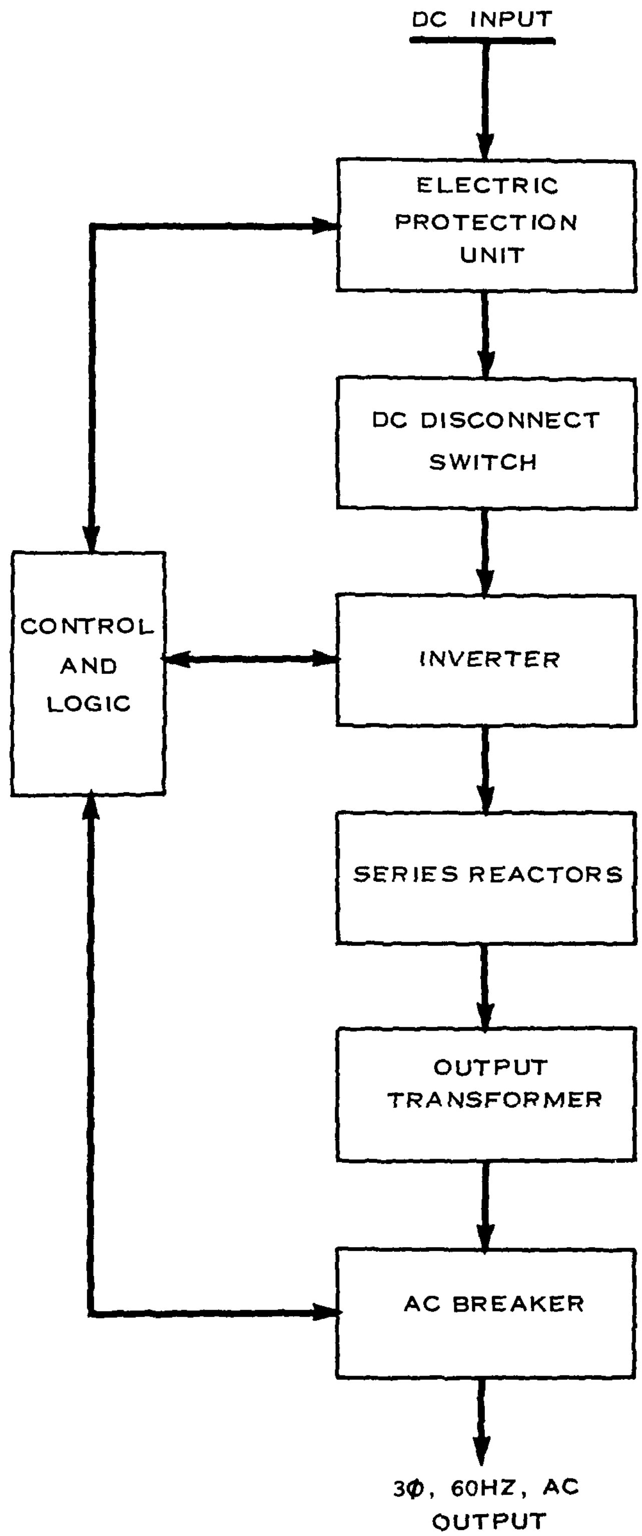


FIGURE 6.4-3 TYPICAL POWER CONVERTER FUNCTIONAL BLOCK DIAGRAM

6.4.2.2 System Description

The power conditioner consists of an electrical protection unit, dc disconnect switch, inverter, series reactance, output transformer and ac breaker. Each of these performs a specific function as described below. Electrical schematic is shown in Figure 6.4-4.

a. Electric Protection Unit

The electric protection unit protects the fuel cell stacks when the system is not producing power and protects against reverse power flow and ground faults.

b. DC Disconnect Switch

The disconnect switch disconnects the fuel cell stacks from the inverter. It may be a switch or circuit breaker with provisions for remote and local operation.

c. Inverter

The inverter converts the dc output of the fuel cell to 3 phase, 60 Hz ac power. The inverter consists of two power channels for 12 pulse operation and operates over a set range of voltage and power output. All components of the inverters are static, with each inverter having six thyristor arms. Each thyristor arm consists of a series connected stack of thyristors. Thyristors are conservatively rated and each thyristor is protected against voltage and current surges. The firing circuits for the thyristors minimize the difference between the firing angles of the individual thyristors in each arm such that they equally share the blocking voltage and total voltage drop. Commutation circuits are also provided for proper functioning of the inverter. The inverter thyristors are forced cooled. The thyristor arms are modular in construction to facilitate maintenance. Thyristors shall be inverter quality and conform to Reference 6.4-3. Filters are provided for the input and output.

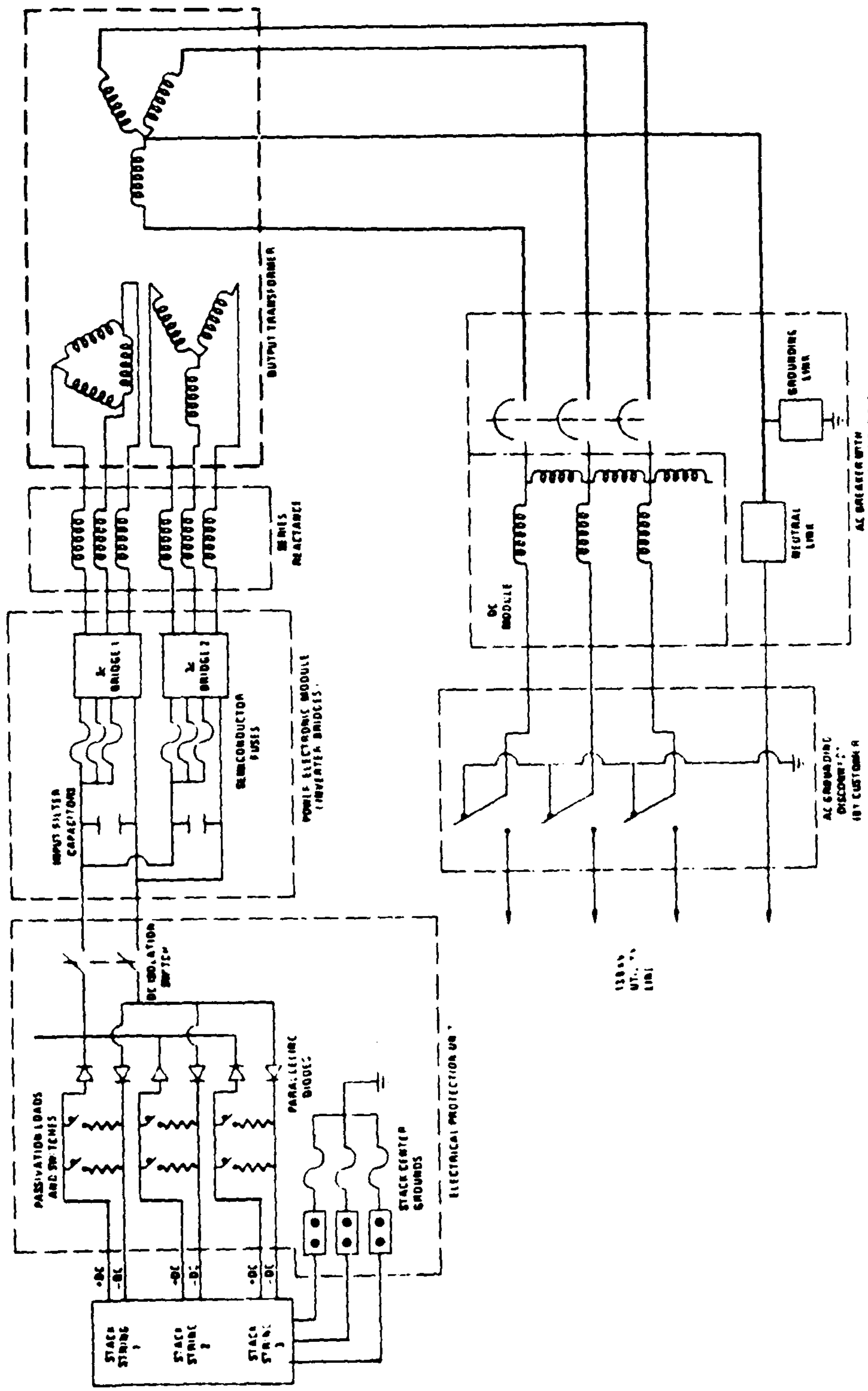


FIGURE 6.4-4 TYPICAL POWER CONVERTER SCHEMATIC

d. Series Reactance

The series reactance functions to control surges, allow for stable control of real and reactive power and reduce output harmonic content. It is be conservatively rated for the application and is a dry type self-cooled. The series reactance along with the output transformer places impedance between the inverter bridges and the ac utility line. They also buffer against utility transients.

e. Output Transformer

The output transformer functions to step-up the inverter ac output to a voltage suitable for interconnection to the TP&L system. The transformer is liquid-filled with natural cooling rated at 11 MVA. The transformer for a 12 pulse system is a three winding transformer with a wye connected high voltage winding. One low voltage winding is connected wye and the other delta. A no-load tap changer with 5 full capacity taps (2 above and 2 below nominal), is provided on the high voltage winding. The transformer is supplied with a liquid level indicator, liquid temperature indicator, gas detector, winding hot spot temperature detector, and sudden pressure relay.

f. Ac Breaker

The ac breaker functions to connect the converter to an ac bus. This bus may be at the facility or a TP&L bus. The breaker is a metal-clad type and may be air-magnetic or vacuum. Protective relays are be provided as required by the Fort Hood facility and TP&L, consistent with good industry practice. Synchronizing equipment will be provided.

6.4.2.3 System Performance

The power conditioner converts dc current from the fuel cell to 3 phase ac power at efficiencies exceeding 90 percent over the entire operating load range of the fuel cell modules. Under design conditions of 11.6 MW gross dc, the power conditioner produces 11.0 MW ac power at a conversion efficiency of 95%. System performance is shown in Table 6.4-5. Availability is expected to exceed 95%.

Operating characteristics of the power conditioner include:

- Operator control of output levels
- Automatic startup and shutdown capability
- Self-regulation of real and reactive power levels
- Self-limiting operation during abnormal ac or dc conditions
- Protection of system during out-of-limit conditions and failures.

The operator controls the mode and desired output of the power conditioner in terms of both real and reactive power levels. During automatic operation the power conditioner either attempts to maintain a preset level of output or match grid demand. The conditioner regulates the fuel cell output by sending a signal for the fuel cell controller to change the output.

The power conditioner has two operating modes and one emergency interrupt state. The operating states are: "standby", where the conditioner is armed to accept a load or go into off status; and "load", where the conditioner is fully operational. A further distinction is made between real and reactive power, where impedance is added to the circuit to produce VAR control. The interrupt condition refers to a situation where the utility grid is in an abnormal state in terms of voltage, current, frequency, phase or voltage.

The power conditoner is of modular design and arranged to facilitate access for removal and replacement of components or for bench repair instead of repair in the confined quarters of the cabinet. This improves the quality of maintenance and reduces the time to restore the power conditioner to service after a shutdown.

The key components are the thyristors which can easily be removed and replaced as needed. The high reliability of the system ensures that down time and maintenance are minimal.

6.4.2.4 Technical Risks

The UTC power conditioner is designed specifically for fuel cell applications. Systems employing similar design concepts have proven to be reliable in utility related applications (Reference 6.4-4). One such system is the power conditioner in the 4.5 MW Tokyo plant which has accumulated more than 4,500,000 kW-hours of operation with no reported problems. Using a design based on the above operating experience, the 11 MW power conditioner by UTC should be expected to provide high performance reliability.

Table 6.4-5 - Power Conditioner Performance Characteristics

Real Power	
Rated	11 MW net ac at sea level, up to 115°F ambient
Minimum	0 MW net ac (STANDBY)
Operating Range	Continuous between 30% and 100% of rated power
Reactive Power	Up to 11 Mvar leading or lagging
Real Power Step Changes	
On Load	1 MW/sec. increase
From STANDBY	15 sec. to rated
From HOLD	15 to 60 min. to rated
Reactive Power Step Changes	
Minimum to Rated	0.2 second
Power Form and Quality	
Output Voltage	Available to match standard grid voltages between 4 and 69 kV, 3-phase
Output Frequency	Nominal 60 Hz (will follow grid frequency between 61 and 57 Hz)
Harmonics	Voltage total harmonic distortion less than 3% of fundamental, no single harmonic greater than 1% fundamental
Voltage Imbalance and Range	Deliver rated power at 2% line-to-line unbalance ± 5% voltage range at rated power (from nominal) +10%, -20% voltage range at reduced power
Fault Current	Limited to 1.1 per unit, rms for one cycle

6.4.3 References

6.4-1 United Technologies Corp., "Description of a Generic 11 MW Fuel Cell Power Plant for Utility Applications". EPRI EM-3161, September 1983.

6.4-2 P.N. Ross, Jr. "The Effect of H_2S and COS in the Fuel Gas on the Performance of Ambient Pressure Phospheric Acid Fuel Cells" Lawrence Berkeley Laboratory LBL - 18001, April 1985.

6.4-3 ANSI C34.2-1968 (R1973), Practices and Requirements for Semiconductor Power Rectifiers.

6.4-4 Ebasco Report PCC-HVDC-001, High Voltage Direct Current (HVDC) Reliability Study, February 13, 1984.

6.5 THERMAL MANAGEMENT SYSTEM

6.5.1 Functions and Design Requirements

Functions

The purpose of the Thermal Management System (TMS) is to convert the thermal and chemical energy flows discharged from the fuel cell and also contained in tars and oils produced in coal gasification into one or more of the following energy forms that can reduce plant operating costs or generate revenue:

1. Steam, hot water and electric power to satisfy the GFC system process demands, thereby lowering plant operating costs, improving plant overall efficiency and minimizing the need to import this energy.

2. Steam for use in the Fort Hood Central Cooling and Heating Plant which supplies chilled water and hot water to the Medical Complex and future Third Corp Headquarters Building.

3. Electric power for export to the electric utility company.

Design Requirements

TMS design requirements are based on interfacing with the following configuration of UTC fuel cell and auxiliary equipment: (1) water cooled, nominal 11 MW UTC fuel cell, consisting of a closed pumping loop with steam drum for the production of saturated steam and (2) a catalytic combustor receiving fuel cell anode and cathode vent gases and subsequent expansion of exiting combustion products through a gas expander-air compressor-motor/generator set.

The TMS receives a fuel cell cooling system heat load of 28.7×10^6 Btu/hr, conveyed by circulating through the fuel cell, 167,000 lb/hr of high purity water and discharging to the TMS as 240 psig, 397°F saturated steam and 5% blowdown water. Makeup water to this system is demineralized, deaerated and heated to at least 242°F.

The gas expander exhausts gas at the rate of 118,100 lb/hr at 705F and 16.5 psia. Properties of this gas mixture include a molecular weight of 28.31 and specific heat of .291 Btu/lb-F. This gas enters the HRSG where it is increased in temperature by mixing with the hot gases produced from the combustion of 1,434 lb/hr of tars and oils produced from coal gasification.

The TMS is designed to meet the following plant process steam, hot water, electric power and export steam requirements:

1. process thermal and power demands, including
   - CO shift boiler steam
   - sulfur slurry heating steam
   - ammonia stripper steam
   - coal gasifier steam
   - CO shift boiler feedwater
   - auxiliary electric power

2. export steam to a new Central Cooling and Heating Plant (CCHP) to satisfy year-round chilled water and hot water requirements.

3. export electric power to the electric utility grid.

The above process and CCHP requirements are listed in Table 6.5-1.

The CCHP average monthly steam demand can be satisfied using the thermal energy generated by the TMS. After satisfying GFC and CCHP process requirements, the remaining steam is used to produce electric power.

Thermal energy contained in the gas expander exhaust flow is recovered in a heat recovery steam generator (HRSG), designed to generate steam at the same pressure and temperature as fuel cell cooling system steam so that the outputs may be combined for input to a steam turbine-generator. The HRSG is designed for supplementary firing of oils and tars produced from coal gasification which raises the temperature of the expander exhaust gas and increases steam output of the HRSG.

In addition to the boiler section, the HRSG shall include an economizer section to preheat TMS makeup water and further lower the gas temperature prior to discharge.

Excess steam shall be expanded through a condensing type steam turbine-generator.

TMS equipment shall be designed for the following expected operating modes:

Mode	Equipment Status
Normal Load	Fuel cell at 100% power; Normal process and export steam loads
Maximum Load	Fuel cell at 100% power; Minimum process and no export steam load
Half Load	Fuel cell at 50% load
Steam Turbine Generator Out of Service$^{(1)}$	Fuel cell at 100% load HRSG partially bypassed
Gas Expander Out of Service$^{(1)}$	Fuel cell at 50% load; HRSG partially bypassed

Notes:

1. Includes reduced load on generator

TABLE 6.5-1

TMS PROCESS CRITERIA

I. Gasifier-Fuel Cell Requirements

A. Process Steam

CO Shift Boiler	-	17,476 lb/hr, 175 psia, 371°F
Sulfur Slurry	-	580 lb/hr, 65 psia, 298°F
Ammonia Stripper	-	2,395 lb/hr, 40 psia, 267°F
Coal Gasifier	-	2,832 lb/hr, 25 psia, 240°F

B. Process Feedwater

CO Shift Boiler	-	2,171 lb/hr, 175 psia, 237°F

C. Process Condensate Return

Gas Processing	-	11,332 lb/hr, 130 psia, 120°F

D. Auxiliary Electric Power - 3,550 KW

6.5.2 System Description

The primary energy output of the fuel cell is the net 11 MW electric AC power produced by the fuel cell power conditioner (EL-601). However, the fuel cell also discharges additional significant energy flows in the form of (1) thermal energy discharged to the fuel cell cooling water system and (2) chemical, pressure and thermal energies vented at the fuel cell anode (fuel gas) and cathode (air). Furthermore, coal gasification generates oils and tars which, has a composition and heating value similar to No. 6 fuel oil and is recovered from the coal gas stream in the Gas Processing Section. The Thermal Management System receives these additional energy flows and converts them to useful thermal, mechanical and electric power supplies that are distributed to meet plant process needs, thus reducing plant operating expenses, or exported to generate revenue.

TMS process flow diagram and stream parameters are given in Figure 6.4-1. This diagram incorporates process thermal loads given in Table 6.5-1. TMS equipment is described in Appendix A. Refer to Table 6.5-2 for stream flows and conditions.

The TMS, as shown Figure 6.4-1, consists of the following major functional areas: fuel cell cooling water; heat recovery steam generator; steam distribution piping; condensing steam turbine and condenser; and condensate storage. These functions are described below:

Fuel Cell Cooling Water

The fuel cell cooling water system removes heat released by the fuel cell exothermic electro-chemical reaction by the forced circulation of condensate through the fuel cell stacks. Condensate exits the equipment as a two-phase mixture which is conveyed to a steam drum where the liquid and steam phases are separated. Steam flow at full load is approximately 28,800 lb/hr. Steam is discharged to TMS steam piping via a pressure control valve which maintains a constant steam drum saturation pressure/temperature of 240 psia/397°F. In case of control valve failure a safety valve protects the system and fuel cell from over pressure.

TABLE 6.5-2

MASS BALANCE - THERMAL MANAGEMENT SYSTEM

Stream No.		33, 34, 35	36	37*	38*	39	40
Stream Name		Expander - HRSG Bypass	HRSG Gas Inlet	Combustion Air	HRSG Burner Gas Outlet	HRSG Gas Outlet	Vent Stack Gas
Components	MW	Lb Mole/Hr	Lb Mole/Hr	Lb Mole/Hr	Lb Mole/Hr	Lb Mole/Hr	Lb Mole/Hr
Ar	39.948	0	23.58	7.2	30.78	30.78	30.78
CO_2	44.01	0	617.52		720.02	720.02	720.02
H_2O	18.016	0	897.59	7.2	965.39	965.39	965.39
N_2	28.016	0	2,618.88	562.5	3,181.68	3,181.68	3,181.68
O_2	32.00	0	14.86	150.6	34.76	34.76	34.76
SO_2	64.06	0	0.01		0.11	0.11	0.11
Total Flow	Lb Mole/Hr	0	4,172.44	727.5	4,932.74	4,932.74	4,932.74
Total FLow	Lb/Hr	0	118,136	20,999	140,568	140,568	140,568
Pressure	Psig	16.5	16.5	16.5	16.5	15.0	15.0
Temperature	F	705	705	60	1,227	218	218

* Stream 38 includes the combustion in 15% excess air (Stream 37) of 1,434 lb/hr oils and tars having a heating value of 17,880 Btu/lb and ultimate analysis of 85.79% C, 8.46% H, 4.82% O, 0.52% N, 0.22% S and 0.19% ash.

TABLE 6.5-2 (Cont'd)

Stream No.		41	42	43	44	45	46
Stream Name		F C Cooling Water In	F C Cooling Water Out	F C Drum Steam	F C Drum Blowdown	F C Drum Water out	F C Cooling Makeup
Flow	Lb/Hr	167,000	167,000	28,790	1,439	136,771	30,229
Pressure	Psia	250	240	240	240	240	275
Temperature	F	370.1	397.4	397.4	397.4	397.4	242.0
Enthalpy	Btu/lb	343.1	515.1	1,200.6	372.3	372.3	210.7

Stream No.		47	48	49	50	51	52
Stream Name		HRSG Boiler Steam	HRSG Boiler Blowdown	HRSG Boiler Feedwater	F W Heater Steam	F W Heater Condensate	Drain Cooler Condensate
Flow	Lb/Hr	38,023	1,901	39,924	5,488	5,488	5,488
Pressure	Psia	240	240	265	230	220	210
Temperature	F	397.4	397.4	372.4	393.7	252.2	123.9
Enthalpy	Btu/Lb	1,200.6	372.3	345.4	1,200.6	220.7	91.9

TABLE 6.5-2 (Cont'd)

Stream No.		53	54	55	56	57	58
Stream Name		Cooling/ Heating Export Steam	Turbine Steam	Extraction Steam	Trbn. Exh. Steam	SJAE Steam	SJAE Condensate
Flow	Lb/Hr	20,300	20,993	5,227	15,766	160	160
Pressure	Psia	175	230	50	2	230	2
Temperature	F	377.4	393.7	281.0	125.4	393.7	125.4
Enthalpy	Btu/lb	1,200.6	1,200.6	1,117.6	977.4	1,200.6	93.4

Stream No.		59	60	61	62	63	64
Stream Name		Trbn. Steam Bypass	Condenser Condensate	Condensate Pump Discharge	Cooling/ Heating Condensate Return	City Water Makeup	Demineral- ized Water Makeup
Flow	Lb/Hr	0	15,766	15,926	20,300	16,882	49,054
Pressure	Psia	230	2	40			40
Temperature	F	393.7	125.4				
Enthalpy	Btu/Lb	1,200.6	93.4				

TABLE 6.5-2 (Cont'd)

Stream No.		65	66	67	68	69	70
Stream Name		Makeup Water Pump Discharge	Blowdown HE CS Outlet	Economizer Water In	Economizer Water Out	Deaerating Htr Steam	FW Pump Suction
Flow	Lb/Hr	70,508	70,508	70,508	70,508	1,816	72,324
Pressure	Psia	86	76	57	47	230	30
Temperature	F	100.0	113.9	124.0	217.0	393.7	242.0
Enthalpy	Btu/lb	68.0	81.9	92.0	185.2	1,200.6	210.7

Stream No.		71	72	73	76	76	78
Stream Name		FW Pump Discharge	Blowdown HE HS Inlet	Blowdown HE HS Outlet	Power Conditioner	Generator EG-601	Generator EG-602
Flow	Lb/Hr	72,324	3,340	3,340	-	-	-
Pressure	Psia	300	240	240	-	-	-
Temperature	F	242.0	397.4	110.0	-	-	-
Enthalpy	Btu/Lb	210.7	372.3	78.0	-	-	-
Power	kW	-	-	-	11,000	2,340	1,150
Volts	V	-	-	-			

A portion of the liquid phase, equal to five (5) percent of the steaming rate, is discharged from the system as blowdown. Blowdown water preheats TMS makeup in heat exchanger E-601. The remaining condensate, plus makeup water to compensate for steam and blowdown losses, is recirculated to the fuel cell by one of (2) 100% fuel cell cooling water pumps (P-601A,B).

For protection of fuel cell components from contamination by cooling system corrosion products, blowdown and makeup water chemistry specifications must be held to within strict limits. To minimize dissolved oxygen contained in the makeup water it is deaerated and heated to 242°F in a direct contact deaerating heater (D-601). Deaerator steam supply is from the TMS steam header.

Makeup water flow is regulated by steam drum water level.

The fuel cell cooling system also contains an electric heater (H-601) which raises the system operating temperature during fuel cell start-up.

Heat Recovery Steam Generator

Gas expander exhaust gas is heated from 705°F to 1227°F by mixing with combustion products from the firing of oils and tars generated during coal gasification and is used to generate steam and hot water in a heat recovery steam generator (HRSG) (B-601). The HRSG consists of auxiliary burner, boiler and economizer sections. Oil/tar fuel is pumped from the Gas Cooling, Cleaning and Compression Section (Figure 6.3-1) and burned with 115% theoretical combustion air from Burner Air Fan C-602. The boiler section, operating at the same steam pressure and temperature as the fuel cell cooling system, 240 psia and 397°F, generates a steam flow of approximately 38,000 lb/hr. Boiler blowdown water equals 5% of the steaming rate and preheats TMS makeup water in blowdown heat exchanger R-601.

Makeup water to the boiler circulating loop is pumped by one of two full capacity feedwater pumps (P-604A, B) from deaerating heater D-601 which deaerates and preheats the makeup water to 26 psia/242°F. Utilizing boiler steam, the direct contact deaerating heater raises the makeup water temperature to saturation temperature while scrubbing the water of non-condensable gases which are vented. The deaerating heater has a condensate storage volume of at least 10 minutes to assure a continued supply of boiler feedwater in case the flow of entering makeup water is interrupted.

The exhaust gas leaving the HRSG boiler section is further cooled to about 218°F in the HRSG economizer section. Makeup water from the condensate storage tank (S-601) is pumped through blowdown heat exchanger E-601, heater drains cooler E-605 and the HRSG economizer where it is heated to 217°F or within about 25°F of deaerator saturation temperature.

Since the normal full load HRSG boiler section gas inlet temperature (with oil/tar firing) is about 1227°F, the HRSG is capable of accepting higher gas temperatures during off normal operation when all or a portion of the gas expander flow is bypassed to the HRSG inlet. For example, if generator G-601 trips, HRSG gas inlet temperature at full load is about 963°F. Furthermore, if gas expander T-601 is out of service (air compressor C-601 being driven by EG-601), HRSG inlet gas temperature is 1201°F. For these cases, the high inlet gas temperature (normally 705°F) requires reductions in oil/tar supplemental firing by about 50% and 100%, respectively, so that HRSG boiler full load HRSG gas temperatures and steaming rates are not exceeded.

Gas exiting the HRSG economizer discharges to the environment through vent stack U-601. Exhaust gas velocity is sufficient for plume dispersion.

Steam Distribution Piping

Total TMS boiler steam flow produced in fuel cell cooling water and HRSG steam drums is about 66,800 lb/hr which is piped at 230 psig to the various process steam users including 20,300 lb/hr average export steam flow to the CCHP. After satisfying thermal loads (see Table 6.5-1) the remaining steam flow of 21,000 lb/hr is conveyed to a turbine-generator for power generation. About 5,200 lb/hr cf 50 psia steam is extracted from the turbine for distribution to coal gasifier and ammonia stripper equipment.

Steam pressure to each process load is regulated by a pressure control device at the point of use.

Steam Turbine/Generator/Condenser

During normal operation about 21,000 lb/hr steam at 230 psia is expanded through a multi-stage condensing type steam turbine (T-602) which drives an electric generator (EG-602) to produce a net output of 1150 kW. An automatic extraction stage supplies steam at 50 psia for process use.

Due to the variability in steam demands for site cooling and heating loads, ammonia stripper and sulfur slurry heating, and the CO shift steam load (which depends on the specific coal delivered), the turbine generator is designed for 150% of normal steam flow or 31,500 lb/hr. The corresponding generator output rating, including 5% margin, is 1850 kW.

Turbine exhaust steam is condensed in a two pass single pressure condenser (E-603) which achieves a turbine exhaust pressure of 4 in. Hga at rated steam flow. The condenser also receives miscellaneous TMS condensate drains (except blowdown) and steam vents. Condenser tubes are stainless steel for maximum corrosion resistance. The condenser hotwell provides a minimum of 5 minutes of condensate storage. One of (2) 100% condensate pumps (P-602A, B) return the condensate to a condensate storage tank (S-601).

Non-condensable gases are evacuated from the condenser by a two-stage steam jet air ejector, (J-601). Condensed ejector steam is discharged to the suction of the condensate pumps.

Condensate Storage

Condensate makeup to TMS equipment is stored in a condensate storage tank (S-601) which receives about 15,900 lb/hr from the condensate pumps

(P-602), 5,500 lb/hr feedwater heater drains (E-605) and 49,100 lb/hr from water treatment system (WT-601). The latter consists of process and export condensate returns plus about 16,900 lb/hr county water makeup which compensates for steam and condensate consumed in process operations discharged TMS boiler blowdown water.

Condensate storage tank minimum storage volume equals 12 hours of full load operation without water makeup.

One of (2) 100% capacity makeup water pumps (P-603A, B) supply condensate through blowdown heat exchanger (E-601), heater drains cooler E-605 and the economizer section of HRSG (B-601) to deaerating heater D-601. Makeup water flow is regulated based on deaerator storage tank water level.

6.5.3 Performance

The TMS is designed to produce steam at 240 psia and 397°F over the 50-100% normal operating range. Full load performance is shown on process flow diagram Figure 6.5-1.

Fuel cell cooling system steam production (B-602) is a function of the fuel cell power conditioner load setpoint and corresponding fuel cell efficiency. Since fuel cell efficiency increases as load decreases (fuel cell stacks operate at approximately 10% higher efficiency at 50% than at 100% load), waste heat production and hence fuel cell boiler steam production tends to drop more rapidly than does fuel cell power output. For example, at 50% GFC plant load, based on an increase in fuel cell efficiency from 50% at full load to 60% at half load, it is estimated that steam flow will be 40% of full load output.

However, the converse is true for the HRSG (B-601) where steam production reduces at a rate that is less than the decrease in fuel cell power. For example, assuming that HRSG inlet gas flow from gas expander T-601 is proportional to fuel cell load but temperature after oil/tars combustion remains constant, at 50% load HRGS steam generator will be approximately 52% of full load output.

At 50% load the HRSG exhaust temperature decreases to approximately 160°F. Being above the dew point temperature of 141°F, no condensation (with potential corrosion) should occur.

In addition to normal operation between 50 to 100% load, the TMS can operate during such abnormal modes as either induction motor/generator EG-601 or gas expander T-601 being out of service. In these cases, full load fuel cell operation can be maintained; however, there will be some reduction in HRSG B-607 steam production.

If load on the turboexpander shaft reduces, due to the motor generator being out of service, 61,400 lb/hr of the total combustor output of 118,100 lb/hr at 1201°F bypasses the expander to prevent an overspeed condition. The expander bypass plus exhaust gas mixture enters the HRSG at 963°F. Being higher than the normal HRSG gas inlet temperature of 705°F, only approximately 50% of full load oils and tars must be fired to achieve a normal HRSG gas temperature of 1227°F. Steam flow will be about 90% of full load.

If gas expander T-601 is out of service, the catalytic combustor exhaust flow at 1201°F bypasses the expander to the HRSG. The high inlet gas temperature, being close to normal operating temperature eliminates the need for oil and tar supplemental firing. Steam flow will be approximately 80% of full load.

The electric output of condensing turbine-generator EG-602 depends on the throttle steam flow available from fuel cell cooling and HRSG boiler drum outputs after the various process and export steam demands are satisfied. The turbine, generator, steam condenser E-603 and condensate pumps P-602A, B, are sized for 150% of normal expected load.

6.5.4 Maintenance

Equipment constituting the TMS is of proven reliability which is sustained during the plant life by well established maintenance procedures, most of which are applied during the annual scheduled shutdown.

Included among these procedures are inspection and replacement (or plugging) of HRSG and steam condenser tubes, relubrication or replacement of bearings, shaft seal replacement, coupling realignment, valve and damper maintenance, calibration and adjustment of controls including turbine governor, vibration check and rotor balancing, replacement of cooling tower fill, etc.

6.5.5 Technical Risks

Because the TMS utilizes proven equipment, there are no technical risks beyond those normally assumed by commercial ventures in mature technologies.

6.5.6 Central Cooling and Heating Plant (CCHP)

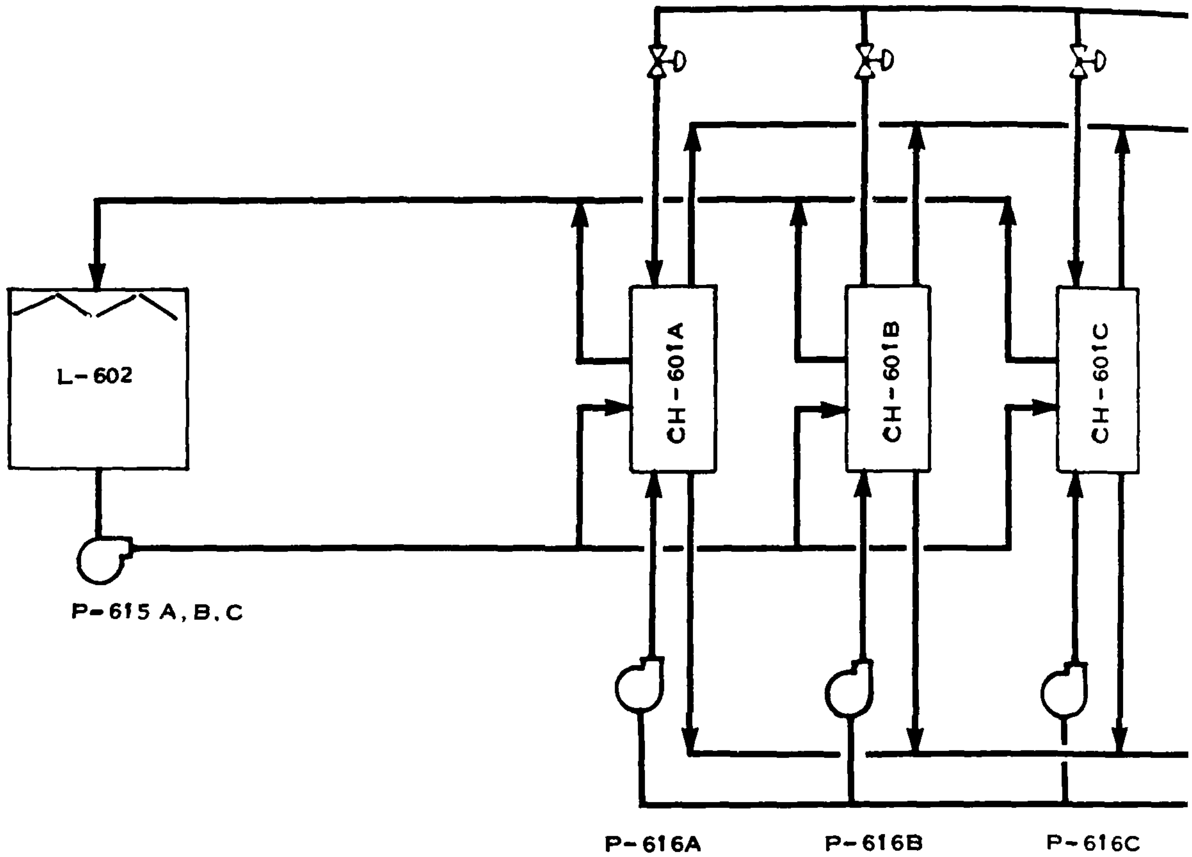
A Central Cooling and Heating Plant located next to the GFC provides for most of the estimated thermal load of the Medical Complex and of the future Third Corp Headquarters Building. This thermal load is discussed in Section 5.0, shown graphically in Figure 5-1 and listed in Table 6.5-3.

When the GFC is operating at or near its rating, the steam flow available for use by the CCHP is 36,100 lb/hr. Based on a two stage absorption steam rate of 12.5 lb/hr-ton, and a base heating load (service water) of 5200 lb/hr, this allows up to 2470 tons of refrigeration plant capacity which exceeds the August average of 2100 tons but which is less than the estimated short term design peak cooling load of 3300 tons.

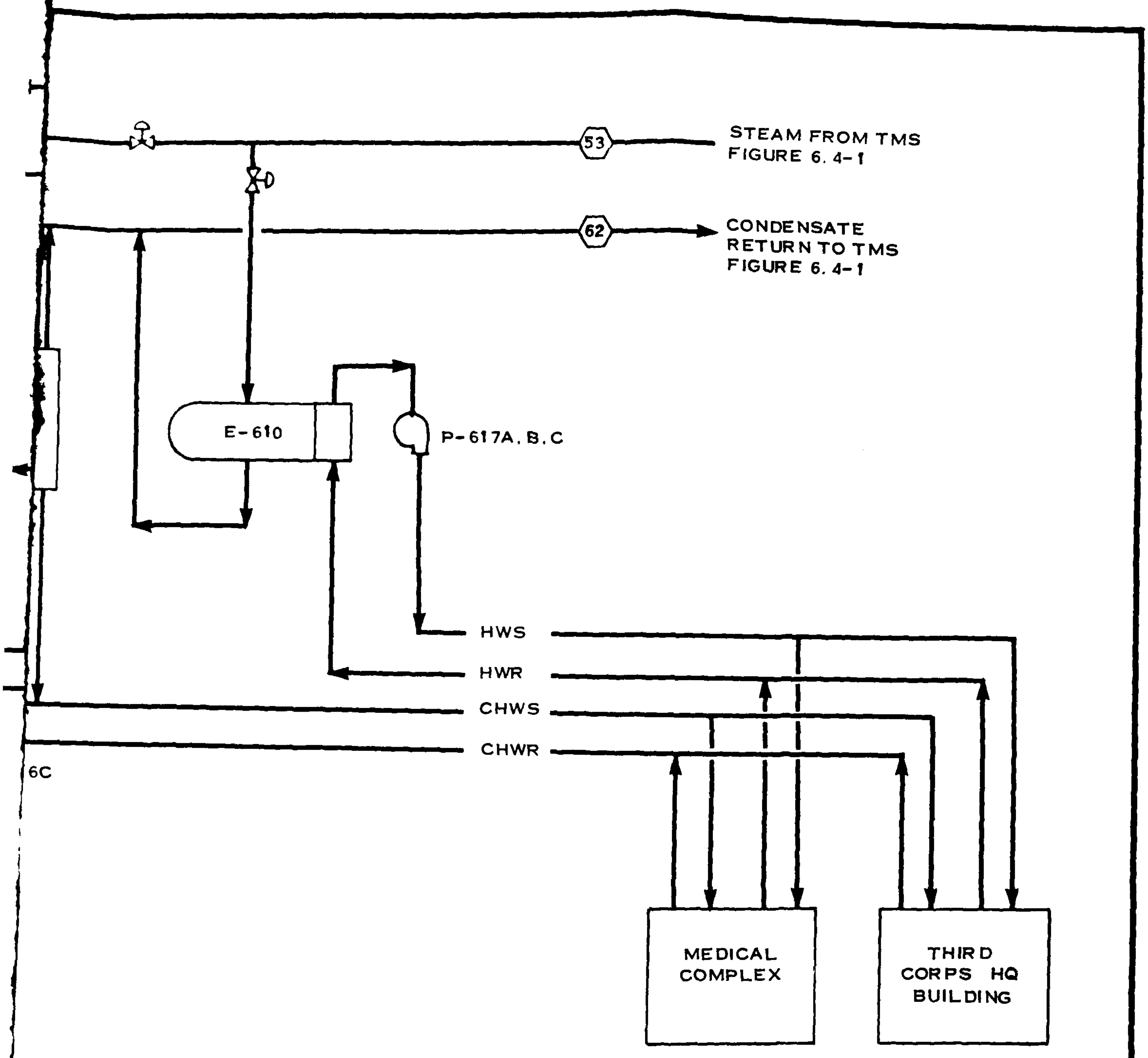
When the CCHP capacity is exceeded, the water chillers located at one or more of the buildings in the Medical Complex may be energized to make up for any shortfall in cooling.

The refrigeration plant consists of three 830 ton two stage absorption water chillers, chilled water and condenser water pumps and cooling tower (See Figure 6.5-1).

Chilled water is distributed in underground mains at 42°F to the Medical Complex and Third Corp Headquarters Building and returned at 58°F.



CH-601	ABSORPTION CHILLER
E-610	STEAM/HOT WATER HEAT EXCHANGER
L-602	COOLING TOWER
P-615	COOLING WATER PUMP
P-616	CHILLED WATER PUMP
P-617	HOT WATER PUMP



DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE

CENTRAL COOLING - HEATING PLANT

FIGURE 6.5 - 1

EBASCO SERVICES INCORPORATED

TABLE 6.5-3

Central Cooling and Heating Plant Steam Demand

Month	Degree Days		Steam Demand(1), lb/hr			
	Heating	Cooling	Heating	Service Water	Cooling	Total
January	599	0	20,246	5,200	0	25,446
February	443	0	14,973	5,200	0	20,173
March	298	7	10,000	5,200	0	15,200
April	159	68	5,374	5,200	2,800	13,374
May	9	217	304	5,200	8,800	14,304
June	0	431	0	5,200	17,400	22,600
July	0	604	0	5,200	24,420	29,620
August	0	648	0	5,200	26,200	31,400
September	1	390	0	5,200	15,800	21,000
October	73	193	2,467	5,200	7,800	15,467
November	265	56	8,957	5,200	2,300	16,457
December	453	3	15,311	5,200	0	20,511
Total Annual	2,300	2,617	45.3×10^6	36.9×10^6	61.7×10^6	143.9×10^6

Notes:

(1) Monthly average steam demands based on estimated peak loads and degree-day data.

(2) Service water distributed from the central plant is used for domestic hot water and to generate steam locally for hospital and kitchen use.

Underground chilled water piping assumed to be water-spread-limiting design (no airspace) with FRP jacket and leak detector/locating cables.

Mains are valved directly to the existing chilled water piping at each building, such that the existing refrigeration plants need only operate when the CCHP is shut down or on peak design days as discussed above.

The heating system consists of a steam to water shell and tube heat exchanger, circulating water pumps, a nitrogen pressurization system, controls and accessories.

Hot water supply and return main temperatures are 320°F and 220°F, respectively at design conditions. Underground hot water piping assumed to be Class A design, dryable, drainable, pressure testable with fiberglass conduit and leak detector/locating cables.

Valved branch runouts from the underground hot water mains connect to shell and tube heat exchangers in each building to provide hot water at a temperature suitable for use in the building heating system. Connections are also provided as required, to generate steam for kitchen and hospital equipment and to heat domestic water.

6.6 Auxiliary Systems

6.6.1 Electrical

Electrical power for auxiliaries including lighting, is provided by an auxiliary power transformer. This may be a dry-type or liquid-filled transformer with natural cooling (e.g., OA or AA). The low voltage winding shall be suitably rated for the electrical auxiliaries (preferably 480 Vac, 3Ø 60Hz). Additional dry-type transformer will be provided for 208Y/120 Vac. Auxiliary loads will be supplied by a variety of devices (e.g, metal-enclosed switchgear, motor control centers and panelboards) as required by the load. In addition, an uninterruptible power supply (UPS) will be provided for critical loads, control and instrumentation. The UPS shall consist of an inverter (with ac and dc inputs), a battery and battery charger. Alternately, some critical loads may be supplied directly from the battery.

Grounding cathodic protection and lightning protection systems are provided. These systems conform to the requirements of IEEE NACE and NFPA.

6.6.2 Cooling Water System

The cooling water system disposes of heat rejected from the coal gasifiers and from various points in the Gas Processing and Thermal Management systems. Referring to Figure 6.6-1, heat is transferred to the cooling water in shell and tube heat exchangers and carried to the cooling tower where it is rejected to the atmosphere. The system maximum cooling load is estimated at 58 million Btu/hr.

Cooling loads for individual users are listed in Table 6.6-1:

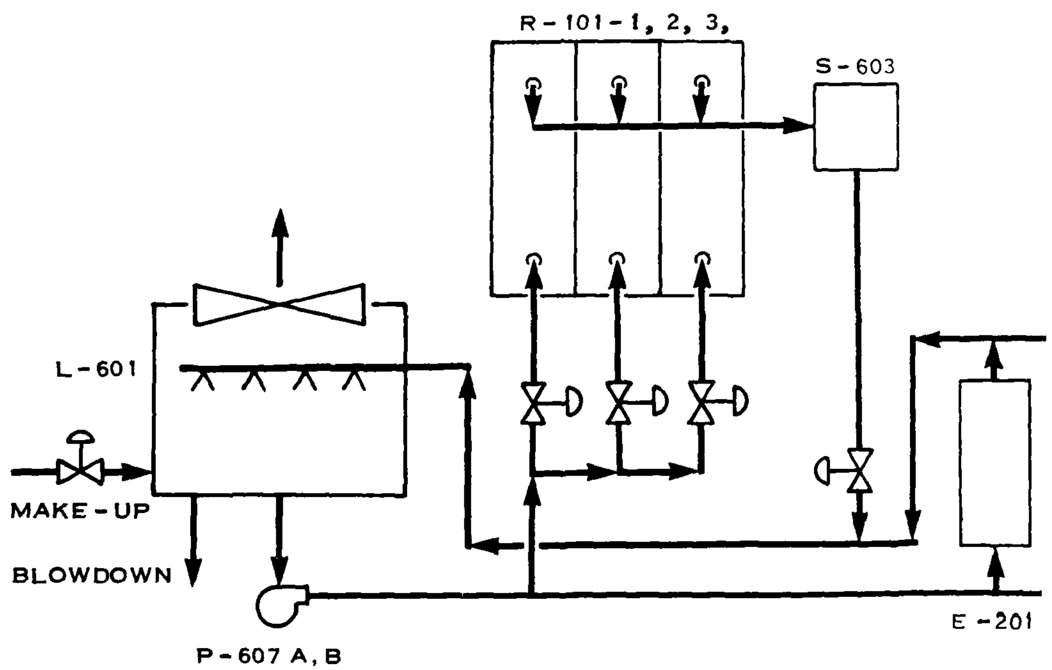
Major components of the cooling water system are the cooling tower, the cooling water pumps and the water supply and return piping.

The cooling tower is of the crossflow, mechanical draft type and provides 85°F cooling water at 9°F wet bulb approach and 20°F range. Air flow through the tower is maintained by axial flow fans with a total power requirement of approximately 160 HP.

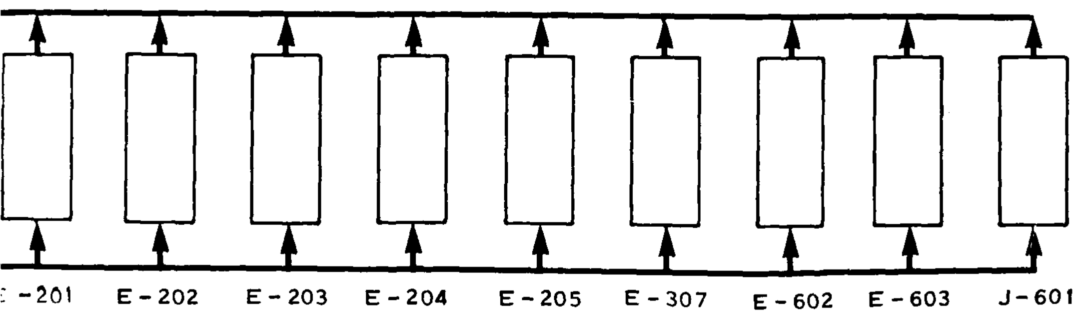
Two 100% capacity cooling water pumps are provided to circulate cooling water through the system. Each pump can deliver approximately 5800 gpm of cooling water at 80 feet total head and is driven by a 150 HP electric motor.

6.6.3 Water Treatment

The Makeup Water Treatment System shown in Figure 6.6-2 will produce a net to service flow of 6.6×10^5 lbs per day of demineralized water based on processing either 100% city water or a mixture of city water and condensate from the Condensate Reclaim System. System design is based on processing 100% city water to meet the makeup water quantity and quality requirements of the fuel cell thermal management system. The expected city water analysis and fuel cell water quality requirements are shown on Table 6.6-2.


R-101-1, 2, 3,
S-603
L-601
MAKE-UP
BLOWDOWN
P-607 A, B
E-201

E - 201	PRIMARY COOLER HEAT EXCHANGER
E - 202	GAS COMPRESSOR 1ST STAGE INTERCOOLER
E - 203	GAS COMPRESSOR 2ND STAGE INTERCOOLER
E - 204	GAS COMPRESSOR 3RD STAGE INTERCOOLER
E - 205	AMMONIA SCRUBBER COOLER
E - 307	CO SHIFT TRIM COOLER
E - 602	AIR COMPRESSOR INTERCOOLER
E - 603	STEAM CONDENSER
J - 601	STEAM JET AIR EJECTOR CONDENSER
L - 601	COOLING TOWER
P - 607	COOLING WATER PUMP
P - 608	GASIFIER COOLING WATER PUMP
R - 101	GASIFIERS
S - 603	OVERFLOW TANK



DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT HOOD, TEXAS SITE
PROCESS FLOW DIAGRAM
COOLING WATER SYSTEM

FIGURE 6.6-1

EBASCO SERVICES INCORPORATED

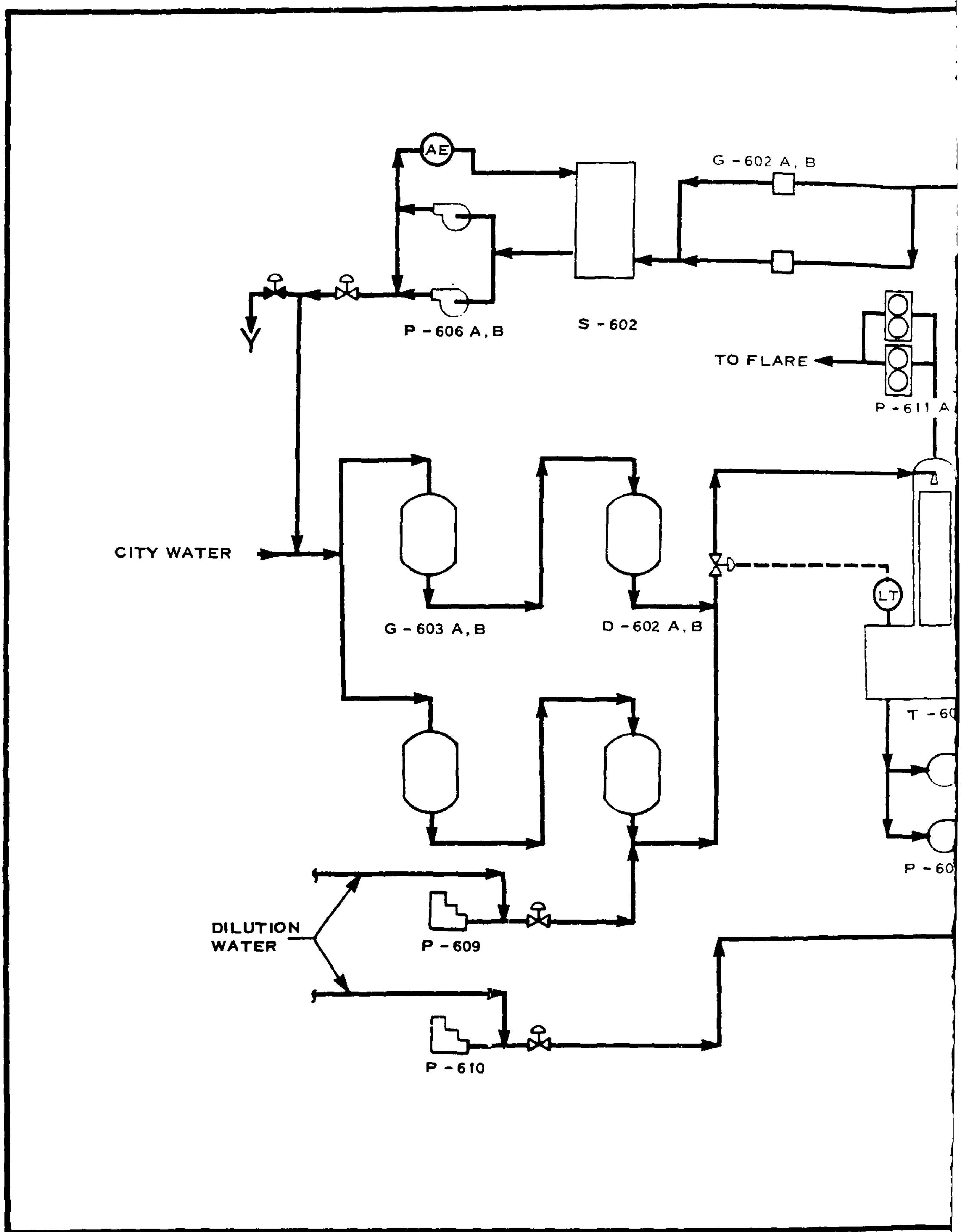
TABLE 6.6-1

COOLING WATER SYSTEM LOADS

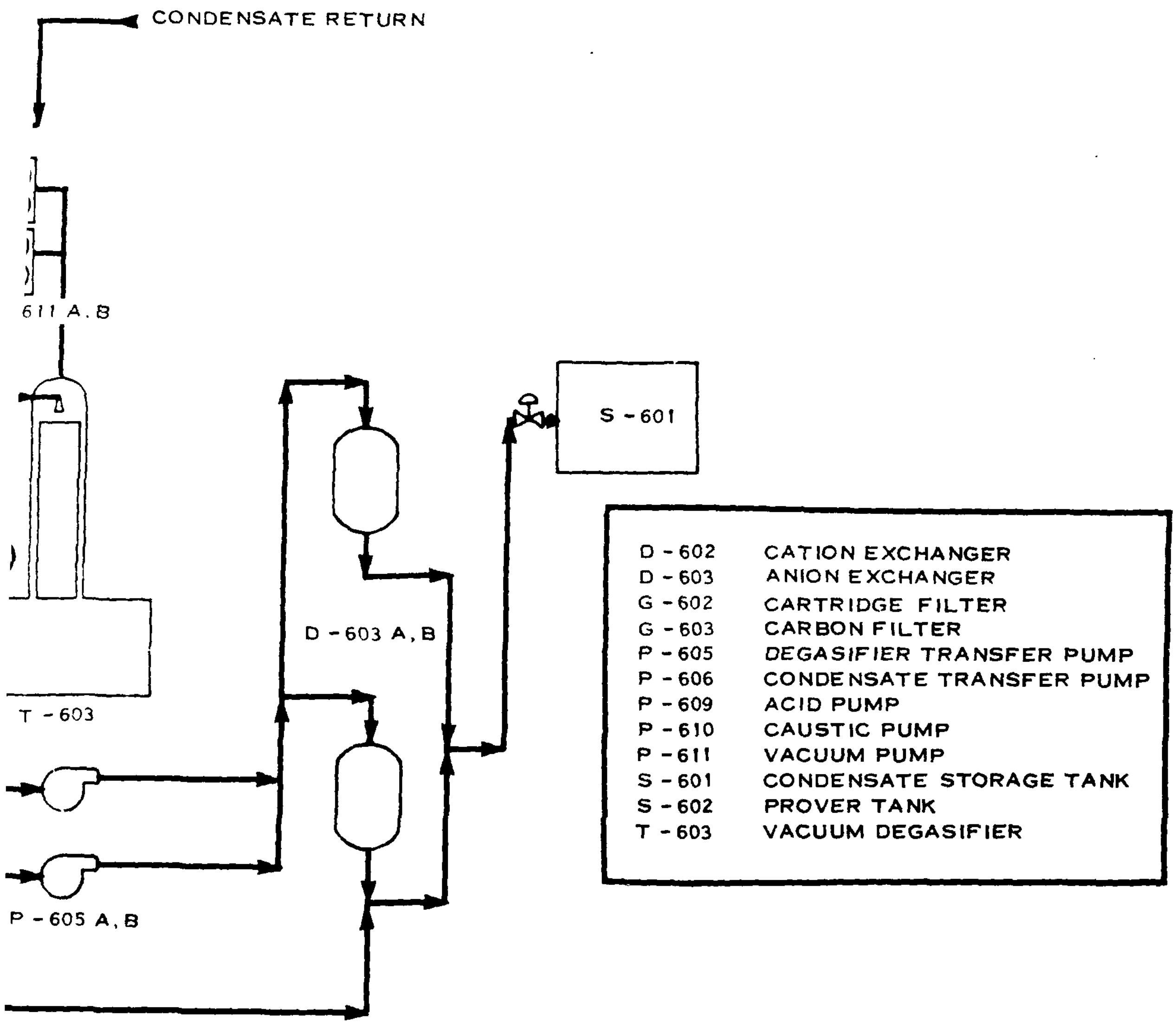
Equipment	Designation	(10^6 Btu/hr)
Coal Gasification		
Coal Gasifiers	R-101	2.87
Gas Cooling Cleaning and Compression		
Primary Cooler Heat Exchanger	E-201	16.15
Gas Compressor 1st Stage Intercooler	E-202	3.10
Gas Compressor 2nd Stage Intercooler	E-203	4.10
Gas Compressor 3rd Stage Intercooler	E-204	3.85
Ammonia Scrubber Cooler	E-205	.18
CO Shift		
Trim Cooler	E-307	.40
Thermal Management		
Air Compressor Intercooler	E-602	3.20
Steam Turbine Condenser	E-603	23.00
SJAE Condenser	E-604	.19
Miscellaneous Coolers		1.14

Makeup Water Treatment System consists of two (2) activated carbon filters, G-603 A&B to remove residual chlorine from the city water, to protect the anion ion exchange resin; two (2) Cation Exchangers, (D-602 A&B); a vacuum degasifier (T-603) with 100% redundant vacuum pumps, VP 601 A&B, and transfer pumps, P605 A&B, to remove dissolved gases such as CO_2 and O_2 from the city water and CO_2, H_2S and HCN from the reclaimed condensate; two (2) Anion Exchangers, (D-603 A&B); a regeneration system, water quality analyzer and a control panel. The system is designed for A or B train to run for 12 hours and produce 4.2×10^5 lbs of demineralized water total. The idle train will then be put into service when the operating train is regenerated. The system is designed for automatic operation and to permit the use of vessels from either train or both trains simultaneously. The design of this regeneration system includes waste neutralization prior to discharge.

The Condensate Reclaim System shown in Figure 6.6-2 filters collects and tests condensate for quality prior to transfer to the inlet of the makeup demineralizer. It is anticipated that the condensate return from the gasifier process will be suitable for reuse in Fuel Cell thermal management cycle. However, to prevent the introduction of excessive dissolved or suspended contaminants the condensate will be filtered through a 10 micron cartridge filter (G 602 A&B) and collected in Condensate Prover Tank, D-602, where it will be analyzed and transferred to the inlet of the Makeup Water Treatment System if it is of acceptable quality. Off standard quality condensate will be sent to the waste treatment system.



G - 602 A, B
AE
P - 606 A, B
S - 602
TO FLARE
P - 611 A
CITY WATER
G - 603 A, B
D - 602 A, B
LT
T - 60
P - 60
DILUTION
WATER
P - 609
P - 610



DOA / GEORGETOWN UNIVERSITY

COAL GAS/FUEL CELL/COGENERATION

FORT HOOD, TEXAS SITE

FUEL CELL

WATER TREATMENT SYSTEM

FIGURE 6.6-2

EBASCO SERVICES INCORPORATED

TABLE 6.6-2

Fuel Cell Makeup Water

Identification: A - Fort Hood Water Supply (Sampled 9/15/84)
B - Fuel Cell Water Quality Requirements

Constituent		PPM as	A	B
Calcium	(Ca**)	$CaCO_3$	88	
Magnesium	(Mg**)	$CaCO_3$	0	
Sodium*	(Na*)	$CaCO_3$	54	
Hydrogen = FMA	(H*)	$CaCO_3$	0	
		$CaCO_3$		
Total Cations		$CaCO_3$	142	
Bicarbonate	(HCO_3)	$CaCO_3$	94	
Carborate	(CO_3)	$CaCO_3$	0	
Hydroxide	(OH^-)	$CaCO_3$	0	
Chloride	(Cl^-)	$CaCO_3$	36	
Sulfate	(SO_4)	$CaCO_3$	12	
Total Anions		$CaCO_3$	142	
Suspended Solids			-	1.0
Iron		Fe	0.16	
Carbon Dioxide, Free*		CO_2	3	0
Silica		SiO_2	5	0.3
pH			7.8	5-7
Total Hardness gr/gal as $CaCO_3$			12	0

6.6.4 Plant Safety

The design of this facility incorporates features required to assure safety of personnel and equipment in the event of an unlikely major leakage of coal gas which is piped at pressures up to 152 psig. The constituents of this coal gas which would be of concern are the hydrogen and the carbon monoxide. The concentration of these components varies through the process from 17 to 32% for hydrogen and from 1 to 24% for carbon monoxide.

The process is located out-of-doors at grade level, effectively reducing the consequences of gas leakage and simplifying its detection and ontrol.

The facility satisfies the criteria of the following governing codes and regulations.

Some of the criteria include:

- OSHA - Requirements for Safe Work places
- NFPA 101 - Life Safety Code
- NFPA 50A - Gaseous Hydrogen Systems
- NFPA 54 - National Fuel Gas Code (Reference)
- NFPA 496 - Purged and Pressurized Enclosures for Electrical Equipment in Hazardous Locations
- NFPA 70 - National Electrical Code
- NFPA - Standards pertaining to detection, suppression and alarm systems

Protection Systems

- Automatic water deluge systems for suppression of ordinary and flammable liquid fires and for reduction of heat, protection of personnel and minimization of facility fire damage.

- Automatic hydrogen and carbon monoxide detection systems and alarms

- Automatic smoke and/or flame sensing detection and alarm systems.

- All protection systems, including safety related ventilation equipment, are status alarmed in the Control Room. Internal communications - both wireless and hardwired - are provided for roving plant personnel.

6.6.5 Nitrogen Gas Supply

Nitrogen gas is used to pressurize the fuel cell stacks during startup, to purge portions of the system during shutdown and to maintain a nitrogen blanket in certain gas processing equipment and the fuel cell stacks during layup. Shutdown of the fuel cell will cause an automatic nitrogen purge.

The system consists of an insulated liquid nitrogen storage tank with approximate dimensions of 7' diameter by 15' high with a capacity of 4000 gallons. The tank is of a standard cryogenic design equipped for truck refill by a commercial supplier. The liquid nitrogen is vaporized by an air heat exchanger for gas delivery to the system. Gas delivery is initiated by a remote manual signal from the control room, and automatically controlled by pressure and flow control valves.

The system is designed to deliver 1000 scfm of nitrogen at 375 psig, and is sized for four complete plant startup/shutdown cycles.

6.6.6 Hydrogen Gas Supply

Hydrogen is needed by the fuel cell during startup and for passivation of the fuel cells during shutdown. On shutdown the fuel cell stacks are automatically passivated with pure hydrogen, and then purged with nitrogen. Passivation of the cell stacks corrects any local electrode polarization that has occurred due to gas impurities and prolongs the effective life of the cell stacks.

The system consists of truck delivered gas cylinders, containing a total of 250 pounds of hydrogen with an automatic pressure and flow control manifold. The system is designed to deliver 75 lb/hr of hydrogen at 375 psig, and it is sized for four startup/shutdown cycles.

6.6.7 Station and Instrument Air

Clean, dry pressurized air is provided to the fuel cell cathode for passivation, to the fuel cell/cathode air compressor for startup and to all pneumatic instruments. The system consists of a 200 scfm air compressor, dryer and a 500 ft^3 air receiver. Delivery pressure is 125 psig.

The system is sized for an 8000 scfm flow for 30 seconds during start-up.

6.7 SYSTEM CONTROL (I&C)

6.7.1 Introduction

The instrumentation and control system is configured with centralized control room and control processors. The input/output hardware is distributed functionally and geographically with the process being controlled, the input/output cards being separated from the controllers/processors so that signal wiring and cable maybe reduced by multiplexing. Each major process has a local subsystem control board located close to the process with sufficient displays and controls to operate the process independently of the Control Room.

This configuration conforms to current state-of-art control and instrumentation practice and results in the reduction in signal wires and cable and related construction costs.

Each sensor, transducer and instrument selected is to be the most reliable for the particular application and from a reputable supplier with an extensive service organization. Although different suppliers may be required to furnish the best instrumentation available, only one supplier furnishes the control hardware. This approach reduces the number of spare parts and maintenance training requirements, simplifies system design and consolidates contractual responsibility.

6.7.2 Control System Configuration

The control system is shown functionally in Figure 6.7-1. This includes a plant system processor and controller for each subsystem process. The plant system processor directs and monitors operation of subsystem controllers, providing the logic and sequencing for startup, operation and shutdown.

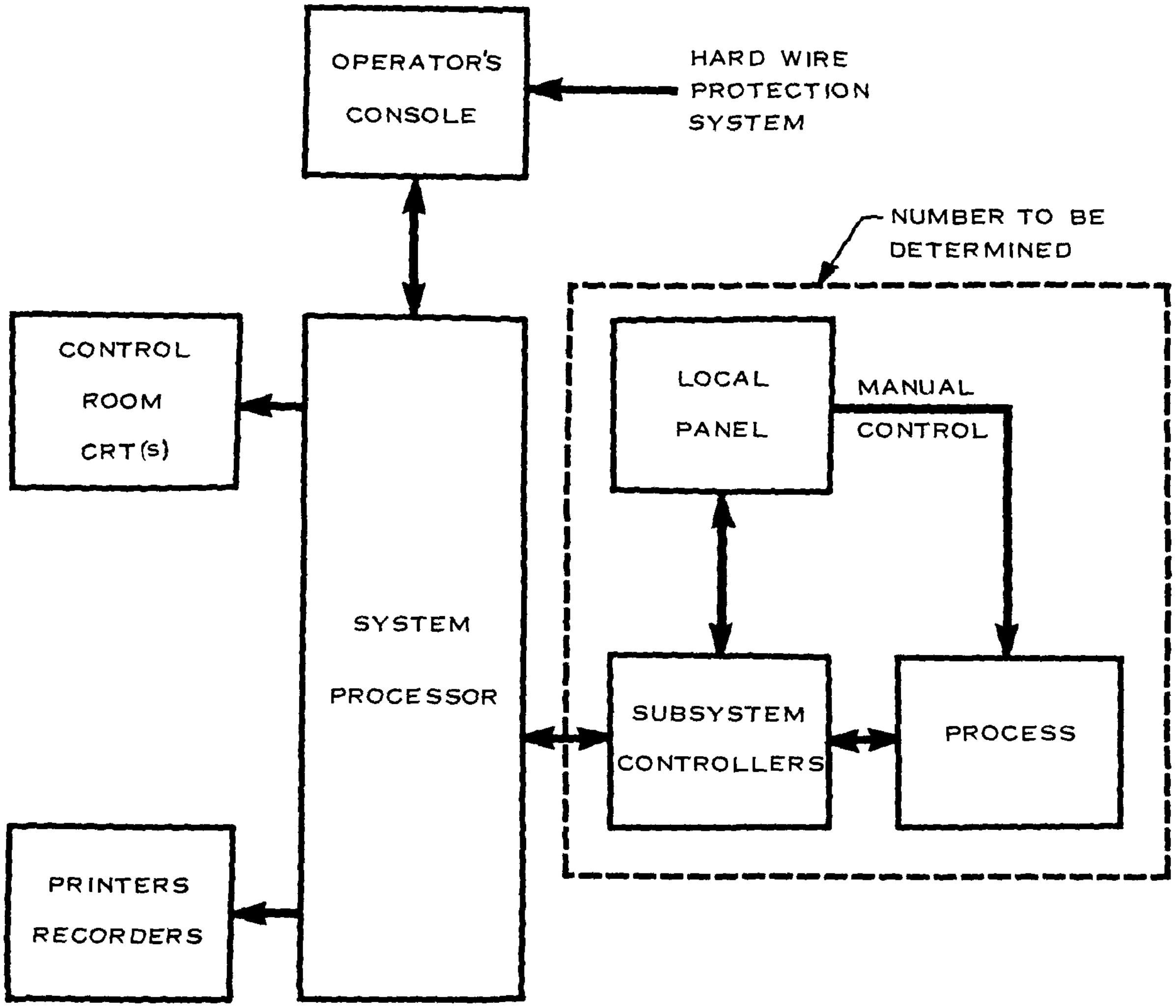


FIGURE 6.7 - 1 CONTROL SYSTEM FUNCTIONAL BLOCK DIAGRAM

The system may be operated from the control room console or from the local subsystem control panels.

The control room contains printers, recorders, CRT's and the operator's control console.

6.7.3 Control Room Layout

The operator interface/peripherals are shown in Figure 6.7-2 and the control room operator's board layout is shown in 6.7-3. The operators console provides for the overall operating mode and power level control in addition to providing dedicated display plant alarms and important process parameters (temperature, pressure, flow, etc).

A separate central analysis console provided for engineering analysis of the process contains a CRT and keyboard to interface with a controller/computer for system analysis. This console is independent of the Control Room operator's console and the local process control boards so that system analysis and performance will not interfere with plant operation.

6.7.4 Control Components and Operation

The system processor (see Figure 6.7-1) is the functional interface with the subsystem controller, furnishing the logic and sequence signals to control the entire plant. Each subsystem, has a controller with local control panel and displays.

There are four color graphic CRT's in the Control Room. One CRT is dedicated to each of the three major processes and the fourth is used for listing alarms and sequence of events during a system malfunction.

One printer is dedicated to preparation of operating and EPA required reports. The second is an alarm logger that tags the alarmed function initially and when it returns to normal.

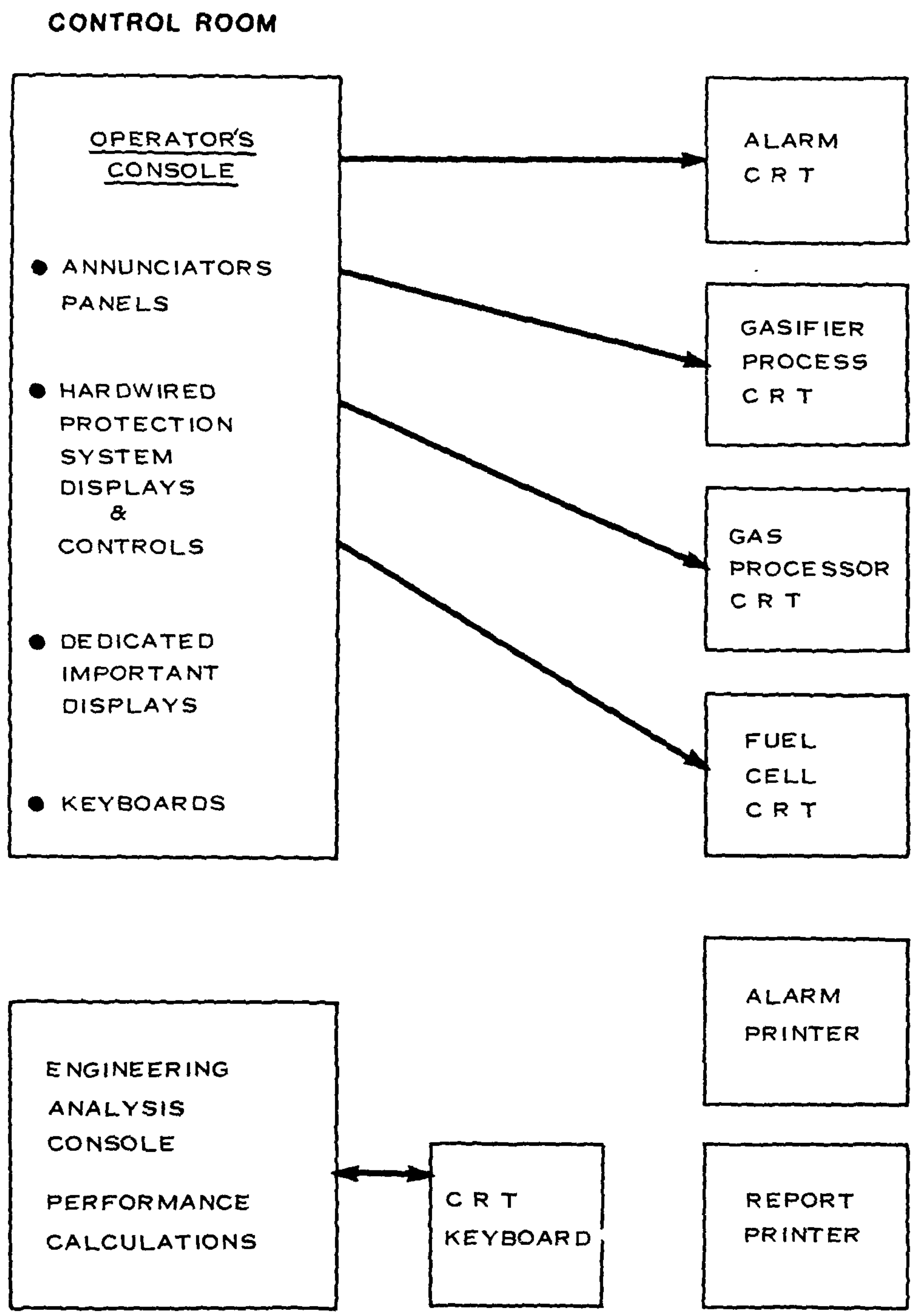


FIGURE 6.7-2 OPERATOR INTERFACE AND PERIPHERALS

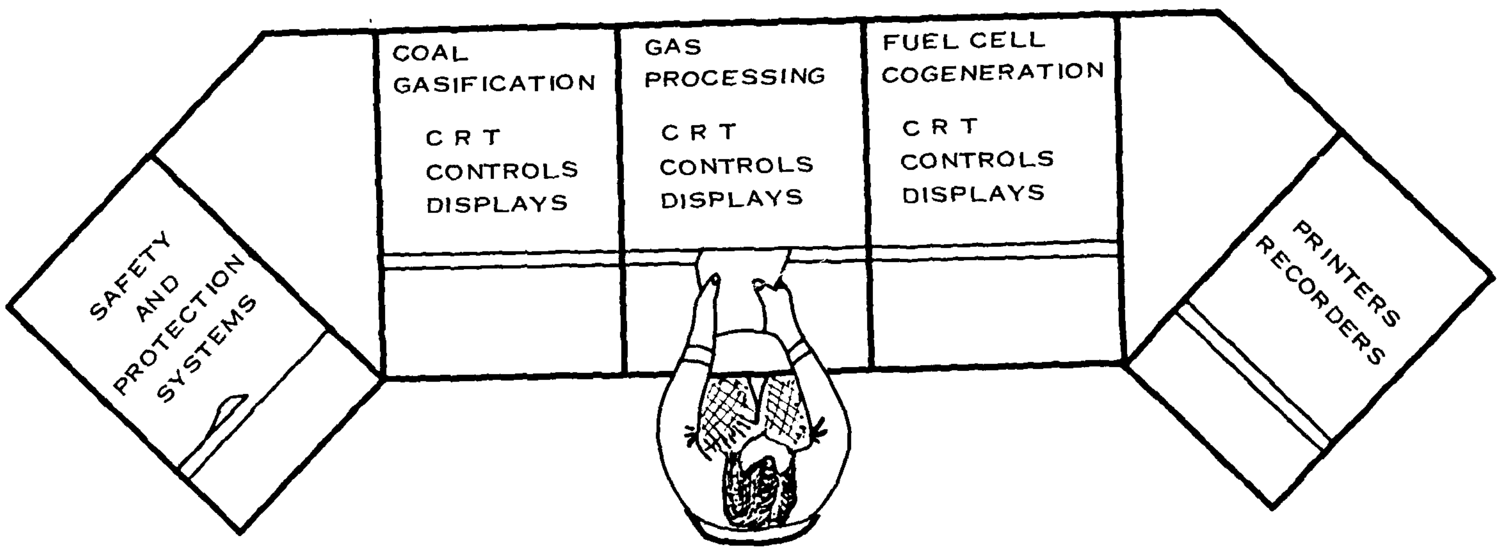


FIGURE 6.7-3 CONTROL ROOM OPERATOR'S BOARD

The process CRT's are color graphic with independent processor, memory and keyboard to format multiple page displays independently of the process controllers. This permits almost instant retrieval of any page without overloading the process controllers, increasing to a point response time.

The control console is in five sections with keyboards, manual controls, dedicated displays, CRT's and annunciator windows. Dedicated displays and manual controls are primarily for the hardwired protection system permitting the operator to override the processors in a major plant upset or component failure. If a failure occurs in the system processor, the plant may continue to operate through local control with subsystem controllers. If a failure occurs in the subsystem controller, there are sufficient manual controls and displays on each local control panel for manual control of the process.

Controls and displays are also included for certain off line ancillaries that are not part of any process subsystem. There is an auxiliary panel in the Control Room for power conditioning and distribution. In addition, there are local auxiliary control panels for material handling (coal and ash), fire protection, and water treatment. A preliminary layout of the control room indicates that approximately 1200 square feet are required for the Control Room and the attached Electronics Room. Supporting facilities, offices, store room, conference room, etc., are not included in this estimate.

6.7.5 Safety

A complete system for monitoring and detection of safety conditions throughout the plant is provided. Conditions including fire, smoke, gas concentration and malfunctions in safety related systems are indicated and annunciated in the Control Room (refer to paragraph 6.6.4). Audio alarms are located as required throughout the plant.

6.7.6 System Control Description

6.7.6.1 Coal Gasification

a. Firebed and Ash Zones

Immediately above the ash bed is the combustion (firebed) zone. In the lower part of the firebed, carbon dioxide is formed from carbon in the fuel and the oxygen in the air/steam blast. Further up, the carbon dioxide combines with carbon and is converted into carbon monoxide. The delivery of the correct quantity of gas with uniform quality is ensured by maintaining these various zones at the proper level and thickness and by a suitable air/steam supply.

The above information on the fire and ash bed is determined by insertion of a steel rod. The dark end of the withdrawn rod indicates the ash depth; the portion of the rod glowing red, indicates the combustion zone; the next darker color indicates the reduction zone. These checks are performed every four to eight hours.

Depth of the fire bed is normally between 4 and 8 inches and of the ash bed, between 12 and 20 inches. If ash bed depth is greater than desired, grate rotation speed is manually increased. Too great a depth of ash can decrease gas production while too shallow a depth reduces grate insulation and protection of the grate from excessive temperatures.

b. Gas Pressure Control

Gas pressure control is the main loop since steam, coal and gasification rates depend on air supply. To prevent air inleakage, the system is maintained under positive pressure. The output of the gasifier is regulated by a recorder controller sensing pressure in the suction line of the gas compressors. As producer gas fuel cell demand increases and line pressure decreases, the controller modulates the air control valve admitting more air to the grate, increasing the rate of gasification. The air flow is modulated to suit demand. E.g., if gas pressure increases, air flow is reduced to lower the gasification rate.

c. Blast Saturation Temperature

Process water is evaporated into the air supply to control the fire bed temperature at a level where gasifier operation is optimized and the ash is prevented from clinkering. The water vapor content of supply air is controlled through a jacket water temperature controller. By modulating a valve in the jacket water circuit, temperature and therefore evaporation rate is maintained at the setpoint. The setpoint may be manually adjusted to maintain optimum firebed conditions.

d. Fuel Feed Level Control

The fuel feed to the gasifier is automatically controlled by a level detector in the upper bin to maintain its setpoint regardless of load change. As fuel is consumed a limit switch actuates the lockhopper valve through a motor operator located under the bin. To fill the lower bin, the bottom valves are closed and the upper valves opened, allowing coal to flow by gravity into the lockhopper. When the lockhopper is filled, usually in a matter of a few minutes, the upper valves close and lower valves open.

e. Grate Rotation

The rotational speed of the gasifier grate is automatically maintained at a point that is manually reset as required to maintain the correct depth of ash, and a safe firebed position.

The grate operates under the control of a timer mechanism consisting of a manually adjustable controller that controls the frequency that oil is admitted to hydraulic through a solenoid valve.

f. Flare Systems

Gasifier output normally matches fuel cell requirements. However, automatic flare systems are provided to burn excess gas which may be produced under off-normal conditions.

These flare systems include a pilot burner with automatic start and shutdown.

The flare is used during startup before the system has been fully purged and pressurized and also while any tests are performed with the gasification system.

Equipment failure is one event which results in excess gas being generated. The gas is flared until the gasifier throughput has been reduced to the appropriate level. In the event of power failure, the gasification system is automatically shutdown as a fail-safe operation with the gas being flared.

The flare is also used to burn any excess fuel gas generated during fuel cell load reduction.

6.7.6.2 Gas Cooling, Cleaning and Compression

a. Anti-Surge Control for Centrifugal Compressors

The differential pressure between the suction and discharge line of the compressor is monitored in conjunction with a discharge line flow controller. The discharge line is defined as downstream of the third stage K.O. drum. A signal generated by differential pressure divided by flow will either open or close a flow control valve to send fuel gas from the discharge line back to the suction line through a bypass line.

b. Ammonium Sulfate Recovery

The ammonium sulfate saturator is controlled by liquid level and temperature. The quantity of sulfuric acid to the tower is controlled by level. Temperature setpoint error in the tower is cascaded to a flow control loop to control flow upstream of the ammonia scrubber exchanger by modulating the valve on the wash liquid line. A manually adjustable controller maintains flow of the ammonium sulfate from the tower at constant rate.

c. Tar Removal and Recovery

The principal control loops are based on level control. Tar pump operation is controlled by a tar collection tank liquid level controller. The tar separator is liquid level controlled for both tar and scrubbing water. In the event the scrubbing water level goes above the preset high liquid level, the blowdown stream will increase.

In addition, the liquor collection tank is level controlled tied to the discharge from the primary cooler pump after the split flow line. The primary cooler is liquid level controlled tied into the discharge from the primary cooler pump and flow controller recorder on the inlet of the scrubbing liquor feed to the tower. In the event the liquid level rises above the high limit the pump will blow down the excess through a by-pass line.

d. CO Shift

The principal control philosophy for the CO shift section is based on maintaining the required temperature and steam to gas ratio inlet to the CO shift reactors. This is accomplished by temperature measurement in the top section of both reactors transmitting signals to the control system to position the valves on the bypass lines around the feed/effluent heat exchanger II and CO shift steam generator. The proper steam to gas ratio to the first CO shift reactor is maintained by flow control of the combined steam line from the CO shift steam generator and import steam line, by modulating the flow control valve on the steam import line. Both reactors will have temperature alarms in the top section of the catalyst bed and analyzer recorder alarms in the exit lines of the reactors to monitor CO concentration and steam to gas ratios.

Both the K.O. drum and trim cooler K.O. drum, are level controlled.

The fuel cell feed heater has a bypass line on temperature control for the fuel gas stream based on a temperature of the COS hydrolysis reactor.

e. Sulfur Removal and Recovery

The principal control loops and instrumentation for the Sulfur Removal and Recovery section are:

- The proper liquid to gas ratio is maintained in the venturi contactor by control of liquid level at the bottom of the vessel in conjunction with a level control valve on the line from the solution heater to the top of the reactor and a flow controller on the line to the venturi scrubber.

- The slurry decanter is level controlled and temperature control is maintained on the steam condensate line to ensure the flow of molten sulfur.

- The zinc oxide beds are flow controlled such that before hydrogen sulfide breakthrough occurs in the first drum there is interchange of flow between the first and second vessel. Both reactors have analyzer recorder alarms for monitoring hydrogen sulfide concentration levels.

- Exiting the zinc oxide vessels, the fuel gas flow to the fuel cells is pressure controlled. In the event there is an increase in line pressure, the control system will send a split signal to: (1) a control valve to open, thereby releasing the fuel gas to a common flare connected with the gasifier and (2) the suction line of the gas compressors pressure control system which in turn sends a signal to the air blower to maintain the required air flow to the gasifier thereby decreasing the gasification rate.

  In the event line pressure decreases the PRC performs the function of increasing the air flow rate thereby increasing fuel gas production.

6.7.6.3 Fuel Cell

The fuel cell system is designed for semi-automatic operation, requiring no operators in addition to those assigned to the Gas Processing Section. The fuel cell system is controlled by micro-processor based controllers that allow the operator to select the operating mode of the plant, and both the real and reactive power. The control system also automatically shuts the plant down during certain upset conditions.

During operation the power conditioner control automatically maintains the desired AC power level. The fuel cell controllers respond to the power demand of the power conditioning system by maintaining the appropriate DC current output. DC current is the prime parameter which controls the setpoints for the remainder of the system. Anode and cathode flow valves are controlled by DC current. The fuel cell controllers also monitor and control certain portions of the other systems to insure proper operation of the fuel cell.

In addition to manually selecting the AC power output, the operator can select any of the following operating modes:

- off
- standby
- load
- hold

In the off state, the fuel cells are maintained under a nitrogen blanket. In the standby mode a start-up sequence is activated. In this mode the cell stacks are pressurized with nitrogen, and various pumps and auxiliary systems are activated or their condition monitored. Using the electric start-up heaters in the Thermal Management System the fuel cell stacks are heated to 350°F. The fuel cells are passivated with hydrogen and the Gas Processing Section is activated such that fuel is flowing to the anode but no air is entering the cathode. On proceeding to load, air is admitted to the cathode and power is produced. When power and voltage exceed the minimum setpoint for the power conditioner, it is automatically activated and power is sent to the utility grid. On entering standby or shutdown mode, the cell stacks are automatically passivated with pure hydrogen from the hydrogen supply system, and the system is purged with nitrogen.

Certain off-standard conditions in the fuel cell system are alarmed and cause automatic shutdown. These include:

- Speed, surge condition, and bearing temperature of cathode air compressor.
- cathode exit temperature
- stack voltage
- hydrogen content in stack enclosure and in cathode exhaust
- oxygen content in anode exhaust
- cell cross pressure
- pallet current difference
- cell pressure
- stack coolant flow

In addition, the status of other systems are monitored, alarmed and can cause shutdown of the fuel cell system if they are not activated or in the proper operational mode.

6.7.6.4 Thermal Management System

TMS equipment operates automatically, maintaining constant boiler steam conditions regardless of fuel cell load or such transient events as loss of power from generator EG-601.

Pressure control valves on steam lines maintain boiler drum and steam user pressures at the required set points.

Makeup water flows to fuel cell and HRSG steam drums (B-602,-601) are regulated by valves controlled from respective drum water levels. Similarly, deaereator (D-601) and condensate tank (S-601) water levels are maintained by makeup water control valves; condenser (E-603) hotwell level is maintained by condensate pump (P-602A,B) discharge valves.

For gas side transients such as generator G-601 trip, gas expander bypass control valves open to prevent expander overspeed.

Oil/tar and combustion air to supplementary burner are modulated to maintain HRSG gas temperatures within operating limits for all normal and abnormal plant operating modes.

7.0 ENVIRONMENTAL

This section reviews the emissions which will be generated by the Fort Hood (TX) Gasification/Fuel Cell/Cogeneration (GFC) System, and briefly discusses the major federal, Texas and local (Bell/Coryell County, City of Kileen) regulatory requirements expected to affect construction and operation of the GFC. For this study it is assumed that all process wastewater will be discharged into existing Fort Hood wastewater collection and treatment systems. Certain air emissions (SO_2 from the supplemental firing of coal tars and oils exceed the threshold emission levels for major modifications under the Federal Clean Air Act Prevention of Significant Deterioration (PSD) permit program. However, it is assumed for this study that: 1) no PSD major sources now exist at Fort Hood; 2) the GFC itself will not be a PSD major source.

Therefore, based on the facts, assumptions, laws, and regulations discussed in this section it appears that: 1) the GFC system as presently conceived requires little or no further emission control measures; 2) the major permits/licenses/approvals necessary for construction and operation of the GFC can be obtained without undue difficulty or delay.

7.1 Summary of Emissions and Regulatory Limitations

Estimates of the air, water, and solid/hazardous waste streams expected to be produced by the GFC are listed in Tables 7-2 through 7-5. For a comparison of GFC system emissions and discharges with regulatory limits, refer to Table 7-1. This table indicates that this project appears to be environmentally acceptable. Major regulatory requirements expected to apply are summarized in Table 7-6.

7.1.1 Air

The GFC emissions (Table 7-2) of SO_2 and NO_x, so-called criteria pollutants, are above the limits which trigger the federal Clean Air Act (CAA) Prevention of Significant Deterioration (PSD) permit process(1). Briefly stated, a major source is defined as: 1) specified kinds of

TABLE 7-1

GFC EMISSIONS VERSUS REGULATORY LIMITS

Air	GFC Emission, (tons/year)	Regulatory Limit, (tons/year) EPA(1)	TX
NO_x	61.8(6)	40	
SO_2	63.2(6)(7)	40	(2)
CO	17.3	100	
Particulates	6.3	25	15.3 (3)
H_2S	0.4	10	(4)

Water	GFC Emissions (mg/l)	Regulatory Limit (mg/l)
COD	150	Regulatory requirements to be determined after assessment of treatability of GFC emissions in existing wastewater treatment facilities.
Phenol	0.3	
Sulfur	Not Available	
pH	(6-8.5)(5) pH units	
Chlorine	less than 0.1	
Metals	Not Available	
Suspended Solids	20	

Solid Waste

Wastes determined to be hazardous will be managed according to requirements of the Resource Conservation and Recovery Act.

Noise

GFC Emission	TX Limit
55 dB at 100 feet	None at the state level

TABLE 7-1 (Cont'd)

Notes:

1. Clean Air Act limits. If these limits are exceeded a federal air permit might have to be obtained for the project.

2. Texas limits SO_2 in the stack to 440 ppm by volume for "liquid fuel-fired steam generation". This might apply to supplemental firing of coal tar and oils.

3. This is the lowest allowable emission rate under Texas regulations.

4. All Texas calculated emission limits are higher than the emission rate expected from the GFC.

5. The pH of project effluent at the point of discharge.

TABLE 7-2

ESTIMATED AIR EMISSIONS

	Emission	Quantity (lb/day)	Source
Coal Handling	Dust	Negligible	
Gasification(1)			Gasifier lock-hopper
	H_2	5.03	
	CO_2	39.00	
	C_2H_4	0.64	
	C_2H_6	0.44	
	N_2	164.86	
	CH_4	3.42	
	CO	94.97	
	H_2S	1.28	
	COS	0.30	
	NH_3	0.14	
	HCN	0.03	
	H_2O	62.14	
Gas Processing	NO_x	31.9	Ammonia Flare
	H_2S	1.09	Stretford Oxidizer
Fuel Cell	NO_x	134	Catalytic Combustor
	SO_x	15.4	
	TSP (Particulates)	4.2	
	Smoke	Negligible	
Thermal Management System	NO_x	252.3	
	SO_x	412.6	
	TSP	38.5	

Notes:

1. Maximum possible emissions per day which could occur during the opening of the lockhopper valves during coal feeding.

TABLE 7-3

ESTIMATED WATER EMISSIONS

	Flow (GPD)	Emission	Concentration (mg/l)	Disposal
Coal Pile Runoff & Dust Suppression	300	Not Available(1)	Not Available	Existing Collection System
Gasification				
Treated Waste Water	39,580			
		COD	150	
		Phenol	0.3	
		NH_3	1	
		Suspended Solids	20	
Sulfur Wash Water	6,540	Sulfur	Not Available	
Ash Sluice Water	300	Not Available		
Fuel Cell	None			
TMS				Existing Collection System
Regen Wastes	10,000	Turbidity	20 NTU (6-8.5) pH units	
Boiler blowdown	4,180	Suspended Solids	20 (6-8.5) pH units	
Cooling Tower Blowdown	11,000	Chlorine	0.1 (6-8.5) pH units	

TABLE 7-4

ESTIMATED SOLID WASTES

	Solid Waste Quantity	Pollutant	Pollutant Quantity	Disposal
Coal Handling	N/A(1)	Dust/Fines	NA	NA
Gasifier				
Ash	43.9 TPD	Trace elements including Be,B, CO, Cr, Cu, Ge, Mn, Ni, U and V.	NA	Carted away to landfill waste disposal
Cyclone Dust	4.3 TPD	Same trace elements as in ash	NA	Carted away to landfill or hazardous waste disposal
Spent Catalysts			NA	Carted away to landfill
CO shift	97 CF/Yr	Sulfur Compounds	NA	
COS Hydrolysis	3 CF/Yr	Sulfur Compounds	NA	
Purged Stretford solution	63 GPD	(2)	(2)	Carted away to hazardous waste disposal
ZnO From Gas Polishing	46 CF/Yr	ZnS	NA	Carted away to landfill
Wastewater Treatment Slurry	714 GPD	Heavy Metals	NA	Carted away to landfill or hazardous waste disposal
Fuel Cell	500 CF/Yr	Heavy Metals in spent catalyst and in replaced cell stacks	NA	Returned to manufacturer for recovery
TMS	None			

Notes:

1. NA - Not available
2. See Table 7-5.

TABLE 7-5

COMPOSITION OF BLOWDOWN FROM STRETFORD PROCESS[1]

Constituent	Concentration (mg/l)
$NaHCO_3$	25,000
Na_2CO_3	5,200
$NaVO_3$	6,600
Anthraquinone Disulfonic Acid	10,000
Iron	50
EDTA	2,700
$Na_2S_2O_3$	120,000
NaCNS	90,000

Note:

1. Based on the complete conversion of HCN in gas feed to NaCNS; 2% conversion of H_2S to $Na_2S_2O_3$; and salt concentration of 25%.

TABLE 7-6

SUMMARY OF ENVIRONMENTAL REQUIREMENTS

Federal

Clean Air Act Prevention of Significant Deterioration Program major modification status investigation

National Environmental Policy Act processing Revision to EPA Form 1 on storm water discharges Clean Air Act New Source Performance Standards for coal preparation plants

Compliance with RCRA solid waste management guidelines

Possible Modification to NPDES permit for ultimate wastewater treatment discharge

Texas

Texas air permit
Possible Modification to Texas permit for ultimate wastewater treatment discharge
Compliance with Texas hazardous waste management system, solid waste management controls

Local (Bell/Ccryell County, City of Kileen)

Possible notification requirement, possible modification requirement for publicity owned wastewater treatment works. Building permits, zoning requirements.

TABLE 7-7

THRESHOLD EMISSION LEVELS FOR MAJOR MODIFICATIONS
UNDER THE CLEAN AIR ACT PSD PERMIT PROGRAM

Pollutant	Emission Rate, tons/yr
CO	100
NO_x	40
SO_2	40
Particulates	25
Ozone	40 of VOC's
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1
Fluorides	3
Sulfuric Acid Mist	7
H_2S	10
Total Reduced Sulfur (including H_2S)	10
Reduced Sulfur Compounds (including H_2S)	10

TABLE 7-8

Applicable Requirements of the Texas Clean Air Act

SO_2 - SO_2 emissions from "liquid fuel-fired steam generators" cannot exceed 440 ppm by volume, unless this figure is decreased by certain stack height corrections. This limitation might apply to air emissions from supplemental firing of coal tars and oils.

Particulates - Texas emission limitations are calculated on the basis of effluent flow rates and effective stack height. The lowest allowable emission rate is 15.3 tons/year; GFC particulate emissions are expected to be 6.3 tons/year.

Opacity - Texas emission limitations require that visible emissions (opacity) cannot exceed 20% averaged over a five minute period. Variance procedures exist from the Texas limitation, based upon technical and economic factors.

H_2S - Texas emission limitations require that H_2 emissions cannot exceed a net ground level concentration of 0.08 ppm averaged over any 30 minute period on contiguous downwind property used or residential, commercial or business property, and 0.12 ppm for other types of downwind property. Formulas are provided for calculation of emission rates to meet these ground level concentration; all of the calculated emission rates are higher than the emission rate expected from the GFC.

Note that Texas air pollution regulations require that new sources show that emissions to be generated are the minimum attainable through the use of "best available control technology". However, the deminimus nature of the GFC emissions lends support to the assumption for purposes of this study that the GFC system, as presently conceived, will require little or no further emission control measures.

sources that emit 100 tons/year or more of any CAA-regulated pollutants and 2) any source which emits 250 tons/year or more of any CAA-regulated pollutant. Major modifications are those which increase emission rates of an existing major source above the threshold values listed in Table 7-7.

Because it appears that there is no "existing major source" at Fort Hood, the GFC, despite exceeding the threshold limits of Table 7-7, is exempt from the requirements of a "major modification".

Permits to Construct and Operate will be required, in accordance with regulations issued under the Texas Clean Air Act. The GFC estimated air emissions are below the levels for "major sources" under Texas law. The following are specific emission limitations expected to apply to the GFC.

7.1.2 Water

For this study it is assumed that the process wastewater streams expected to be produced by the GFC (Table 7-3) will be discharged to existing Fort Hood wastewater collection and treatment systems.

Note that the volume of the wastes expected (approximately 72,000 gpd) represents and increase of over 50% of the current average wste water flow from area No. 10 which includes the GFC site (124,000 gpd, with a peak flow of 469,000 gpd). The 21-inch line from the area has a capacity of 7 million gpd.

The regulatory consequences of the additional GFC waste streams depend upon whether or not these increase the volume of effluent or quantity of pollutants in the ultimate discharge from the wastewater treatment system. If so, a modification of that discharge permit may be required. Note that since Texas has not been delegated the NPDES permitting power, a dual permit is issued by both Texas and EPA Region VI.

Since the wastewater treatment system in question appears to be designed for treating wastewater from a large area of Fort Hood, it is assumed for this study that the additional GFC emissions can be treated in existing wastewater treatment facilities and that any necessary permit modifications can be obtained without undue delay or difficulty.

7.1.3 Solid/Hazardous Wastes

The solid/hazardous waste streams expected to be produced by the GFC are summarized in Table 7-4 and 7-5. Since Texas administers the Resource Conservation and Recovery Act (RCRA)[2] it will be necessary to determine which of these streams are considered hazardous waste under Texas regulations.

The tars and oils produced during coal gasification will be used for supplemental firing and heat recovery. It is anticipated that at least some of these materials will exhibit the ignitability characteristic (liquid, flash point less than 60°C). The burning of hazardous wastes for legitimate energy recovery purposes is currently exempt from RCRA regulation. However, EPA has stated its intention to develop regulations governing these practices[3].

It is anticipated that Fort Hood has systems in place for collection, holding, and offsite removal of the solid and hazardous wastes streams now being generated. For this study is assumed that the additional GFC waste streams can be easily integrated into these existing procedures.

7.2 Applicable Laws and Regulations

The major federal, Texas and local laws and regulations expected to affect construction and operation of the GFC will be briefly noted. This discussion is permised upon the assumptions and estimated emissions already discussed.

7.2.1 Air

7.2.1.1 Federal

A federal Clean Air Act permit could be required for the GFC, because the quantity of regulated pollutants is sufficient to activate the PSD permit process. As discussed in para. 7.1.1, it appears that PSD application processing will not be required. However, it appears that the GFC must comply with the New Source Performance Standard (NSPS) for "coal preparation plants", which would limit opacity from the coal handling section of the GFC to below 20%.

7.2.1.2 Texas

As discussed above, the Texas Clean Air Act will require Permits to Construct and Operate. These permits are issued upon a showing that the GFC will meet all applicable Federal and Texas regulations, and will utilize the "Best Available Control Technology", with consideration given to the technical practicability and economic reasonableness of reducing or eliminating the emissions from the facility. Since the GFC is not considered a "major source" under Texas standards, for this study it appears that the necessary approvals likely can be obtained upon a showing that the emission limitations discussed above and set forth in Table 7-8 (SO_2, Particulates, Opacity, H_2S) will be met by the GFC.

7.2.2 Water

7.2.2.1 Federal

The federal Clean Water Act National Pollutant Discharge Elimination System (NPDES) permit program in Texas is administered by EPA Region VI in Dallas. Therefore, a modification to a fedral NPDES permit may be required if the GFC waste streams will change either the volume of effluent or quantity of pollutants discharged from the wastewater treatment plant accepting the GFC waste streams.

7.2.2.2 Texas

As discussed above, it is anticipated that wastewater from the GFC will be discharged into the existing wastewater treatment system serving area No. 10 at Fort Hood. The ultimate discharge from this wastewater treatment system into a surface waterbody is regulated by a discharge permit jointly issued by the state of Texas and EPA Region VI. This dual permitting results from the fact that Texas has not been delegated the NPDES permitting authority. To avoid duplication of effort and hardship on the permittee, Texas and EPA alternate lead roles in permitting and usually issue identical permits.

For this study it is assumed that the additional GFC waste streams can be treated by the existing wastewater treatment system serving area No. 10 of Fort Hood. If any additional volume of discharge or quantity of pollutants results from the addition of the GFC waste streams, a modification may be required to the Texas/EPA ultimate discharge permit.

7.2.2.3 Local

The wastewater treatment facilities which will accept the GFC waste streams may be under the jurisdiction of a local government such as Bell County, Coryell County, or the City of Killeen. If so, the local sewer ordinance would improve notification requirements prior to discharge of the GFC wastes into the wastewater collection system.

In the alternative, Fort Hood may have its own wastewater treatment system, with its own operating license and ultimate discharge permit. If so, special conditions in that permit are expected to require an evaluation of treatability of the additional GFC wastes, and possible notification of Texas and EPA Region VI regarding a permit modification.

7.2.3 Solid/Hazardous Waste

7.2.3.1 Federal

The Resource Conservation and Recovery Act (RCRA) regulates the management of hazardous wastes and, to some extent, the management of non-hazardous solid wastes. The GFC facility, is also subject to the RCRA solid waste management guidelines for federal facilities. It is assumed that these have already been implemented at Fort Hood.

7.2.3.2 Texas

The hazardous waste management program of Texas governs hazardous wastes generated at the GFC. Note that state hazardous waste management programs can be more inclusive or stringent than the Federal RCRA regulations. It is assumed that Ford Hood is already managing several types of hazardous wastes and that the additional GFC waste streams will pose no problems.

As discussed above, it is anticipated that at least some of these materials will be classified and hazardous wastes. The supplemental firing of these materials at the GFC for heat recovery purposes is currently exempt from RCRA regulations; however, EPA may regulates these practices in the future.

Texas hazardous waste regulations are more stringent than those of EPA. Texas currently also exempts burning of hazardous wastes for energy recovery (4), but could choose to regulate these activities in the future even if EPA decides not to regulate supplemental firing of coal tars and oils. In general, states with delegated RCRA programs follow EPA's lead, unless there is a strong local concern not addressed by the EPA regulations.

It is expected that the GFC project will also be subject to the laws and regulations of Coryell County which may require approvals and permits relating to construction, zoning, etc.

7.2.4 National Environmental Policy Act

NEPA requires federal agencies to consider the effects of their actions upon the human evironment. The Department of the Army (DOA) is required to undertake a NEPA review of the GFC project because of the use of federal funds and the construction of a new energy facility for an army installation (5).

Note that the level of NEPA compliance varies with the expected impact of the proposed action. For this study it is assumed that a full Environmental Impact Statement (EIS) will not be required. It is anticipated that DOA would prepare an Environmental Assessment, a relatively brief document, and issue a Finding of No Significant Impact (FONSI) after review and public comment on the EA.

7.3 References

7-1 Codes of Federal Regulations, Title 40, Part 52.21

7-2 Code of Federal Regulations, Title 40, Parts 261-271

7-3 Federal Register Vol. 50, p. 630 (January 4, 1985)
Federal Register Vol. 50, p. 17824 (April 29, 1985)

7-4 Texas Administrative Code, Title 25, Chapter 325.274 (a)(1)(c)(ii).

7-5 Code of Federal Regulations, Title 32, Part 651

7-6 Publication AP-42, Compilation of Air Pollutant Emission Factors, Supplement No. 9, July 1979, US Environmental Protection Agency, p. C-6.

7-7 EPA-600/7-80-097, Environmental Assessment: Source Test and Evaluation Report - Wellman-Galusha Low-Btu Gasification, May 1980. Tables A-1 through A-5.

8.0 APPENDICES

A. Equipment List

B. Attacheo References

APPENDIX A

EQUIPMENT LIST

COAL HANDLING AND STORAGE SECTION

Item No	Quantity	Description
H-001	1	24" Variable speed Belt Feeder, 150 TPH Estimated HP=/0
H-002	1	24" Belt Conveyor 450' lg x130' lift 150 TPH, Lignite, 400 FPM, HP=30
H-012	1	24" Belt Weighfeeder w/variable speed drive, rate indicator, totalizer, flow gate, and dust hopper w/scavenger screw. 0-40 TPH Estimated HP=5
H-009	1	24" Belt Conveyor 330 ft. lg x 90 lift 40 TPH, lignite, 150 FPM, 15 HP
H-011	1	24" Tripper Conveyor w/self propelled tripper. Present length 190 ft., future extended length 300 ft. Lift=50 ft., 40 TPH, lignite, 150 FPM. Estimate HP includes future extension. Conveyor = 15 HP for Tripper = 5
H013	1	Vibrating Screen 40 TPH, -1/4 opening Estimated HP=10
P-001,A,B	2	Sump Pump 50 GPM' Estimated HP = 2HP, Each
P-002A,B	2	Sump Pump 15 GPM' Estimated HP = 1/2 HP, each
S-001	1	Enclosed grizzly, steel receiving hopper 14'x14' square top x 15' deep w/water spray nozzle and dust control system.
S-002	1	30' Dia. 96' high, silo, 600 T capacity, lignite, 45 Lb/ft^3 w/10 ft. clearance under discharge cone.

EQUIPMENT LIST

COAL HANDLING AND STORAGE SECTION (Cont'd)

Item No	Quantity	Description
S-003	1	Fines silo, 150' Dia. x 43' high w/manual discharge gate w/16' clearance under discharge gate
T-001	1	Truck scale w/automatic ticket printer
T-002	1	Magnegic separator Estimated HP=2
G-001	1	Bag type dust collector w/2 100% capacity blowers at 30 HP

COAL GASIFICATION SECTION

Item No	Quantity	Description
R-101, A, B & C	3	Coal Gasification system including airblown, atmospheric pressure, single stage, 10' ID fixed-bed coal gasifier and cyclone dust collector (H-102 A, B & C)

EQUIPMENT LIST

Item No	Quantity	Description
GAS COOLING CLEANING AND COMPRESSION SECTION		
C-201	1	Gas compressor - centrifugal, stainless steel, three stage w/inter cooling between stages, with a capacity of 11,200 SCFM and designed for 172 psia at 150°F, driven by 3228 hp electric motor. Including oil system, seal system and instrumentation.
D-201	1	Gas compressor 1st stage K.O. drum, - stainless steel, with mist eliminator designed for 31 psig at 150°F, 4'-7" diameter x 9'-0" high
D-202	1	Gas compressor 2nd stage K.O. drum, - stainless steel, with mist eliminator designed for 80 psig at 150°F, 5'-0" diameter x 9'-6" high
D-203	1	Gas compressor 3rd stage K.O. drum, - stainless steel, with mist eliminator designed for 157 psig at 150°F, 4'-6" diameter x 8'-9" high
D-204	1	Tar separator - coalescer plates installed in fabricated steel tank, 10'x 3' x 3' high with a capacity of 80 gpm.
E-201	1	Liquor cooler, - designed for 16.15 x 10^6 Btu/Hr duty, with 1287 ft^2 effective area, in carbon steel
E-202	1	Gas Compressor 1st stage intercooler, with stainless steel tubes and carbon steel shell, designed for a duty of 3.1 x 10^6 Btu/Hr duty, with 513 ft^2 effective area. Furnished with C-201
E-203	1	Gas Compressor 2nd stage intercooler, with stainless steel tubes and carbon steel shell, designed for 4.1 x 10^6 Btu/Hr duty, with 679 ft^2 effective area. Furnished with C-201

EQUIPMENT LIST (Cont'd)

GAS COOLING CLEANING AND COMPRESSION SECTION (Cont'd)

Item No	Quantity	Description
E-204	1	Gas Compressor 3rd stage cooler, with stainless steel tubes and carbon steel shell, designed for 3.85×10^6 Btu/Hr duty, with 638 ft^2 effective area. Furnished with C-201
E-205	1	Ammonia scrubber cooler, with stainless steel tubes and carbon steel shell, designed for 180,000 Btu/Hr duty, with 110 ft^2 effective area
P-201 A, B	2 (1 Spare)	Saturator pump, - carbon steel centrifugal horizontal, rated for 176 gpm at 70 ft, driven by 5 hp electric motor
P-202 A, B	2 (1 Spare)	Tar pump-carbon steel gear type, rated for 10 gpm and driven 1/3 hp electric motor
P-203 A, B	2 (1 Spare)	Liquor pump-carbon steel centrifugal horizontal rated for 84 gpm at 40 ft, driven by 1.5 hp electric motor
P-204 A, B	2 (1 Spare)	Primary cooler pump, stainless steel centrifugal horizontal rated for 3586 gpm at 120 ft, driven by 150 hp electric motor
P-205 A, B	2 (1 Spare)	Acid circulation pump, - stainless steel centrifugal horizontal, rated for 44 gpm at 50 ft, driven by 1.5 hp electric motor
S-201	1	Tar collection tank - ton capacity vertical carbon steel tank designed for 30 psig at 205°F. 5' diameter x 14' high
S-202	1	Liquor collection tank - 3 ton capacity vertical carbon steel tank designed for 30 psig at 180°F. 3'-6" diameter x 10'-0 high

EQUIPMENT LIST (Cont'd)

GAS COOLING CLEANING AND COMPRESSION SECTION (Cont'd)

Item No	Quantity	Description
T-201	1	Saturator - direct contact spray tower, designed for 30 psig at 530°F, in carbon steel. 5'-3" diameter x 68'-0" high
T-202	1	Primary cooler - venturi type scrubber, designed for 30 psig at 200°F, in carbon steel with stainless steel internals. 8'-0" diameter x 21'-0" high
T-203	1	Ammonium sulfate saturator - stainless steel tower, designed for 173 psig at 150°F. 3'-6' diameter x 15'-0" high
U-201	1	Dispersed phase precipitator - wet electrostatic precipitator, designed for 28,500 ACFM, with 99% efficiency, 26.3KW, 37 KVA, carbon steel.

EQUIPMENT LIST (Cont'd)

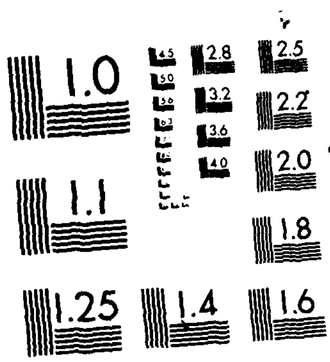
CO SHIFT SECTION

Item No	Quantity	Description
D-301	1	K.O. Drum - stainless steel vessel designed for 150 psig at 260°F, with wire mesh separator. 3'-2" diameter x 6'-0" high
D-302	1	Trim Cooler K.O. Drum - stainless steel vessel designed for 145 psig at 150°F, with wire mesh separator. 3'-2" diameter x 6'-0" high
E-301	1	Feed/Effluent Heat Exchanger II- designed for 4.25 x 10^6 Btu/Hr duty with 330 FT^2 effective area. 1-1/4 Cr-1/2 MO tubes, stainless steel shell.
E-302	1	Feed/Effluent Heat Exchanger I - designed for 2.38 x 10^6 Btu/Hr duty with 194 ft^2 effective area. 1-1/4 Cr - 1/2 MO tubes, stainless steel shell
E-303	1	CO Shift Steam Generator - Kettle type heat exchanger designed for 2.15x 10^6 Btu/Hr duty with 355 ft^2 effective area. 1-1/4 Cr - 1/2 MO tubes, stainless steel shell
E-304	1	Fuel Cell Feed Preheater - stainless steel heat exchanger designed for 4.53 x 10^6 Btu/Hr duty with 876 ft^2 effective area
E-305	1	Feed Gas Preheater - stainless steel heat exchanger designed for 2.88 x 10^6 Btu/Hr duty with 1323 ft^2 effective area
E-306	1	Air Cooler - stainless steel, designed for 13.4 x 10^6 Btu/Hr duty with 3752 ft^2 effective area and 75 hp fan
E-307	1	Trim Cooler - designed for 0.4 x 10^6 Btu/Hr duty with 282 ft^2 effective area. Stainless steel tubes and carbon steel shell

AD-A173 690 FEASIBILITY STUDY OF COAL GASIFICATION/FUEL CELL/COGENERATION PROJECT FOR.. (U) EBASCO SERVICES INC NEW YORK B ROSSI ET AL. JUL 85 DAAG29-85-C-0007 3/3

UNCLASSIFIED F/G 10/2 NL

END
DATE
FILMED
12-86



MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

EQUIPMENT LIST (Cont'd)

CO SHIFT SECTION (Cont'd)

Item No	Quantity	Description
F-301	1	Start-up Heater - fired heater, designed for 18 x 10^6 Btu/hr duty and used for start-up only
R-301	1	1st CO Shift Reactor - 1-1/4 Cr-1/2 MO converter, designed for 175 psig at 930°F. 4'-6' diameter x 14' - 0" high packed with 160 ft^3 sulfided shift catalyst
R-302	1	2nd CO Shift Reactor - 1-1/4 Cr-1/2 MO converter, designed for 175 psig at 610°F. 4'-6' diameter x 13'- 2" high, packed with 145 ft^3 sulfided shift catalyst

SULFUR REMOVAL AND RECOVERY SECTION

Item No	Quantity	Description
D-402 A, B	2	ZnO Drum - carbon steel vessel designcd for 125 psig at 425°F 13'-0" diameter x 18' - 6" high, packed with 1930 ft^3 ZnO absorbent
R-401	1	Hydrolysis Reactor - carbon steel vessel designed for 125 psig at 425°F,, 6'-0" diameter x 12' - 0" high, packed with 226 FT^3 COS hydrolysis catalyst
X-401	1	Stretford Sulfur Removal and Recovery Package, including: C-401 Air blower D-401 Slurry decanter E-401 Solution heater H-401 Solid separation, wash and reslurry S-401 Oxidizer tank S-402 Balance tank S-403 Slurry tank T-401 Venturi contactor Nominal sulfur capacity 2.18 STPD

PROCESS CONDENSATE TREATMENT SECTION

Item No	Quantity	Description
G-501 A, B	2 (1 Spare)	Carbon Filter - carbon steel plate and frame filter press designed for 2300 gpd flow with 4.5% solids dewatered to 35% solids

EQUIPMENT LIST (Cont'd)

PROCESS CONDENSATE TREATMENT SECTION (Cont'd)

Item No	Quantity	Description
E-501	1	Sour Water Heater - stainless steel heat exchanger, designed for 1.32 x 10^6 Btu/Hr duty with 40 ft^2 effective area
P-501 A, B	2 (1 spare)	Sour Water Pump - stainless steel centrifugal horizontal rated for 25 gpm at 120 ft and driven by 2 hp electric motor
P-502 A, B	2 (1 spare)	Waste Water Pump - stainless steel centrifugal horizontal, rated for 28 gpm at 40 ft and driven by 1/2 hp electric motor
P-506 A, B	2 (1 spare)	Recycle Water Pump - carbon steel centrifugal horizontal, rated for 115 gpm at 40 ft and driven by 2 hp electric motor
S-501	1	Sour Water Storage - stainless steel horizontal tank designed 15 psig at 180°F 14'-0" diameter 12" - 0 high
T-501	1	Ammonia Stripper - carbon steel tower designed for 30 psig at 300°F. 3'-8' diameter x 30' - 0" high and packed with 2 inch ceramic intalox saddles.
X-501	1	Waste Water Treatment System - Powder Activated Carbon Treatment (PACT) package including: C-501 Air blower H-501 Virgin carbon storage H-502 Polyelectrolyte storage P-503 Virgin carbon feed pump P-504 Polyelectrolyte feed pump S-502 Settling tank S-503 Aeration contact tank

EQUIPMENT LIST (Cont'd)

FUEL CELL SECTION

Item No	Quantity	Description
C-601	1	Two stage air compressor with intercooler. Gear driven by turboexpander. Complete with controlling instrumentation, seal and lubrication system. 14,967 scfm, at 3217 HP.
CC-601	1	Catalytic Combustor. Pressure vessel containing Pt/Pd catalyst on metalor ceramic matrix, complete with mixing manifold.
E-602	1	Intercooler heat exchanger for air compressor. 3.2×10^6 Btu/Hr duty with 200 gpm cooling water flow.
EG-601	1	Electric Generator, gear driven by turboexpander, 2.46 MW.
F-601	1	Air Filter for air compressor intake.
FC-601	18	Water cooled phosphoric acid fuel cell stacks by UTC. Pressure vessel 6' dia by 11' 6" high, containing 500 cells each of 10.6 ft^2 of active electrode surface. Vessels are skid mounted in groups of three along with prefabricated piping. Vessels complete with insulation, freeze protection heaters, and hydrogen leak detection instrumentation. Gross output of 18 stacks is 11.6 MWe DC.
GA-601	1	Station and Instrument Air. 200 SCFM compressor, with 500 ft^3 air reservoir. Delivery pressure 125 psig.
GH-601	1	Hydrogen gas supply system 250 lb of hydrogen stored in pressure cylinders with flow and pressure control. Delivery pressure 375 psig.
GN-601	1	Nitrogen gas supply system. Consisting of 7' diameter by 15' high liquid nitrogen storage tank, complete with vaporizing liquid/air heat exchanger and pressure/flow control. Delivery pressure 375 psig.

EQUIPMENT LIST (Cont'd)

FUEL CELL SECTION (Cont'd)

Item No	Quantity	Description
T-601	1	Turboexpander, shaft linked with air compressor, 6698 HP

POWER CONDITIONING SECTION

Item No	Quantity	Description
PC-601	1	11 MW power conditioning converted system including inverter bridges series reactors, dc switchgear
PC-602	1	Electrical Protection Unit
PC-603	1	Output transformer 3-winding, liquid-filled 11 MVA, 3Ø, 13800/480V.
PC-604	1	15 kV class metal-clad breaker
PC-605	1	Auxiliary power transformer 2500 kVA, 13800/480V.
PC-606	1 Lot	Miscellaneous transformers 480/208/120V
PC-607	1 Lot	Power Panels
PC-608	1	480 V Motor Control Center

EQUIPMENT LIST (Cont'd)

THERMAL MANAGEMENT SECTION

Item No	Quantity	Description
B-601	1	Heat Recovery Steam Generator: inlet gas - 118,136 lb/hr, 705'F; auxiliary burner fuel 1,434 lb/hr oils/tans, 25.64 x 10^6 Btu/hr; heater gas 1,227 °F; steam output 38.023 lb/hr, 240 psia, 397 °F; economizer water 70,508 lb/hr, 124 °F inlet, 217°F outlet; 5% boiler blowdown; surface area 10,700 ft^2 (est.) economizer section; design pressure/temperature gas side 10 psig/1300°F, steam side 350 psig/450°F; 25°F pinch point; 98% efficiency; 20,999 lb/hr combustion air (includes 15% excess)
C-602	2 (1 spare)	HRSG Burner Air Fan centrifugal, forced draft; testblock flow 5,400 cfm, state pressure 80 in. WG; 125 hp motor
D-601	1	Deaerating Heater: inlet water 70,508 lb/hr, 217°F; outlet water 26 psia, 242°F; heating steam 1,200.6 Btu/lb; 10 minute water storage capacity (153 gal)
E-601	1	Blowdown Heat Exchanger, stainless steel, hot side inlet water 3,340 lb/h, 397°F; cold side inlet water 70,509 lb/h, 100°F; 10°F drains approach temperature
E-603	1	Steam Surface Condenser: Rated steam flow 26,300 lb/hr, duty 23.2 x 10^6 Btu/lb, 4 in. Hga; two-pass 3/4 in. dia x 19 ft long x 22 BWG stainless steel tubes; 7 ft/s tube water; 85% cleanliness factor; surface area 2,100 ft^2 (est.); cooling water 2,320 gpm, 92°F, 112°F outlet; 5 minute hotwell storage (260 gal)

E-604	1	Feedwater Heater: feedwater 39,924 lb/hr, 242°F inlet, 372°F outlet; steam 230 psia, 1,200.6 Btu/lb; 10F drain approach temperature; stainless steel tubes; surface area 160 ft2 condensing section, 90 ft2 drain cover section.
E-605	1	Heater Drains Cooler: herater drains 5,488 lb/hr, 252°F inlet, 10°F drain approach; cold side 70,508 lb/hr, 114°F inlet, 124°F outlet; stainless steel tubes; surface area 80 ft^2 (est.)
EG-602	1	Electric Generator: rated output 1,850 kW
J-601	1	Steam Jet Air Ejector: 1" Hga, two-stage with inter- aftercondenser, 230 psia steam
P-601 A, B	2 (1 spare)	Fuel cell cooling water pump, 420 gpm 150 ft TDH, 25 hp motor, 3500 rpm, 300 lb rating, 316 stainless steel fitted parts
P-602 A, B	2 (1 spare)	Condensate Pump: 60 gpm, 130 ft TDH, 3 hp motor, stainless steel fitted

EQUIPMENT LIST (Cont'd)

THERMAL MANAGEMENT SECTION (Cont'd)

Item No	Quantity	Description
P-603 A, B	2 (1 spare)	Makeup Water Pump: 155 gpm, 185 ft TDH, 12.5 hp motor, stainless steel fitted
P-604 A, B	2 (1 spare)	Feedwater pump; 170 gpm, 725 ft TDH, 50 hp motor, 300 lb rating, stainless steel fitted materials.
S-601	1	Condensate Storage Tank, 24,300 gal usable storage, 13.5 ft diameter x 24 ft high, lined carbon steel with rubber bladder.
T-602	1	Steam turbine, condensing type, multi-stage with automatic extraction, inlet steam 230 psia, 1200.6 Btu/lb, 31,500 lb/hr rated flow; extraction steam 5,200 lb/hr, 50 psia; exhaust pressure, 4.0 in Hga; steam rate 41.1 lb/kWh upper stages, 24.3 lb/kWh lower stages; 3,600 rpm.
U-601	1	Vent Stack, 36 in diameter 87 ft carbon steel.

EQUIPMENT LIST (Cont'd)

CENTRAL COOLING WATER SECTION

Item No	Quantity	Description
CH-601 A to D	3	Absorption Chiller, 830 Ton, 1450 gpm, 42°F chilled water, 10,500 lb/hr 159 psia steam; 2800 gpm, 85°F cooling water; 11 ft x 26 ft x 14 ft high.
E-610	1	Steam/Hot Water Heat Exchanger, 51 x 10^6 Btu/hr, 230 psia steam, 550 ft^2 effective surface area, stainless steel tubes, carbon steel shell.
L-602	1	Cooling Tower, forced draft, cross flow, 8,400 gpm, 85° outlet temperature, 8°F approach, 14° range, 6 cells each with 25 HP 2 speed fan.
P-615 A to D	3	Condenser Water Pump, centrifugal, horizontal, 2800 gpm, 70 ft head, 75 HP motor, bronze impeller, east iron casing, stainless steel shaft.
P-616 A to D	3	Chilled Water Pump, centrifugal, horizontal, 1450 gpm, 350 ft head, 200 HP motor, bronze impeller, cast iron casing, stainless steel shaft.
P-617 A to D	4	Hot Water Pump, centrifugal horizontal, 260 gpm, 360 ft head, 50 HP motor, stainless steel impeller, casing and shaft.

EQUIPMENT LIST (Cont'd)

COOLING WATER SECTION

Item No	Quantity	Description
L-601	1	Cooling Tower, Forced draft, cross-flow, 5800 gpm, 85°F outlet temperature, 9°F approach , 20°F range consisting of 4 cells each with a 40 HP motor driven fan. Overall dimensions 21 ft wide, 48 ft long, 13 ft high. Operating weight 94,000 lb.
P-607 A, B	2 (1 spare)	Cooling Water Pump, centrifugal, horizontal, 5800 gpm, 80 ft head, driven by a 150 HP motor. Materials: Bronze impeller, CI casing, stainless steel shaft. Dimensions: 42" wide, 43" high, 80" long. Operating Weight 4,100 lb.
S-603	1	Gasifier Overflow Tank, carbon steel, 3 ft diameter, 4 ft high.

EQUIPMENT LIST (Cont'd)

WATER TREATMENT SYSTEM

Item No	Quantity	Description
D-602 A, B	2	Cation Exchanger: 4'0" diameter 10'-0" straight side with dished heads. Vessel - rubberlined carbon steel, PVC piping and internals Resin-Strong Acid Cation 6'0" bed depth - Countercurrent regeneration with blocking flow
D-603 A, B	2	Anion Exchanger: 4'0" diameter 12'-0" straight side with dished heads. Vessel - rubberlined carbon steel, PVC piping and internals Resin-Strong Acid Cation 6'0" bed depth - Countercurrent regeneration with blocking flow
G-602 A, B	2	Cartridge Filter - 10 micron cartridge filters, duplex arrangement PVC lined ductile iron housing. Quick disconnect cover for cartridge replacement. Inlet and outlet 2 inch flanged connections, 150 lb design
G-603 A, B	2	Carbon Filter - 3'0" diameter x 7' 6" straight side with dished heads. Vessel - coated carbon steel with PVC piping and internals. Activated Carbon - 3'-0" bed depth. Anthaicite Subfill - 1'-5" bed depth
P-605 A, B	2 (1 spare)	Degasifier Transfer Pump - horizontal centrifugal type pump. Rated at 50 gpm and 100 ft TDH. 3 HP motor at 3600 rpm FRP casing and impeller
P-606 A, B	2 (1 spare)	Condensate Transfer Pump - horizontal centrifugal type pump. Rated at 25 gpm and 100 ft TDH. 3 HP motor at 1800 rpm
P-611 A, B	2 (1 spare)	Vacuum Pump Liquid Ring Vacuum Pump. 975 RPM pump speed with belt drive and 10 HP motor. Cast iron casing.

EQUIPMENT LIST (Cont'd)

WATER TREATMENT SYSTEM

Item No	Quantity	Description
S-602	1	Condensate Prover Tank 500 gal FRP tank with rubber bladder
T-603	1	Vacuum Degasifier: 2'-6" diameter 19'-0" straight tower with 250 gal clearwell. Vessel - coated carbon steel with PVC internals. Packing: Maspac FN-200 60 cu ft.

APPENDIX B

ATTACHED REFERENCES

Referenced materials are listed at the end of each chapter. Most of these references were submitted with the March 1985 Report CLIN 0001. New references are attached.

Reference No.	Title
5-1	Unnumbered pages entitled "FY 84 Energy Consumption" from FY 85 Energy Plan.
7-6	Publication AP-42, Compilation of Air Pollutant Emission Factors, Supplement No. 9, July 1979, US Environmental Protection Agency, p. C-6.
7-7	EPA-600/7-80-097, Environmental Assessment: Source Test and Evaluation Report - Wellman-Galusha Low-Btu Gasification, May 1980. Tables A-1 through A-5.

REF. 110.5-1

FY 84 ENERGY CONSUMPTION
(MBTU's)

	April	May	June	3rd Qtr	July	August	September	4th Qtr	TOTALS
Electric									
goal	198088	253922	355101	807111	399988	421202	338475	1159665	3186150
actual	208253	304088	388118	900459	412524	419126	344566	1176216	3319107
%dev	5.132%	19.756%	9.298%	11.566%	3.134%	-0.493%	1.800%	1.427%	4.173%
cum %dev	2.344%	4.989%	5.744%		5.314%	4.455%	4.173%		
Nat Gas									
goal	98096	58636	53296	210028	44048	44987	52103	141138	1629850
actual	86172	65369	58295	209836	57795	61170	70472	189437	1668094
%dev	-12.155%	11.483%	9.380%	-0.091%	31.209%	35.973%	35.255%	34.221%	2.346%
cum %dev	-1.582%	-1.049%	-0.675%		0.241%	1.260%	2.346%		
Other									
actual	57	0	95	152	0	0	312	312	2319
Facility									
goal	296184	312558	408397	1017139	444036	466189	390578	1300803	4816000
actual	294482	369457	446508	1110447	470319	480296	415350	1365965	4989520
%dev	-0.575%	18.204%	9.332%	9.174%	5.919%	3.026%	6.342%	5.009%	3.603%
cum %dev	0.478%	2.261%	3.083%		3.401%	3.361%	3.603%		
Mobility									
goal	135360	135361	135361	406082	104575	104575	104574	313724	1466000
actual	135435	123825	102992	362252	130631	116195	143497	390323	1500001
%dev	0.055%	-8.522%	-23.913%	-10.793%	24.916%	11.112%	37.221%	24.416%	2.319%
cum %dev	0.148%	-1.006%	-3.697%		-1.316%	-0.362%	2.319%		
Total									
goal	431544	447919	543758	1423221	548611	570764	495152	1614527	6282000
actual	429917	493282	549500	1472699	600950	596491	558847	1756288	6489521
%dev	-0.377%	10.128%	1.056%	3.476%	9.540%	4.507%	12.864%	8.780%	3.303%
cum %dev	0.399%	1.455%	1.409%		2.264%	2.485%	3.303%		

FY 84 ENERGY CONSUMPTION
(MBTU's)

	October	November	December	1st Qtr	January	February	March	2nd Qtr	SUB-TOTAL
Electric									
goal	241217	202129	203233	646579	219050	164548	189197	572795	1219374
actual	262030	195244	191657	648931	212713	190293	190495	593501	1242432
%dev	8.628%	-3.406%	-5.696%	0.364%	-2.893%	15.646%	0.686%	3.615%	1.891%
cum %dev	8.628%	3.142%	0.364%		-0.460%	2.112%	1.891%		
Nat Gas									
goal	72786	158108	261511	492405	298188	302122	185969	786279	1278684
actual	73145	131999	333156	538300	340891	211643	177987	730521	1268821
%dev	0.493%	-16.513%	27.397%	9.321%	14.321%	-29.948%	-4.292%	-7.091%	-0.771%
cum %dev	0.493%	-11.152%	9.321%		11.207%	-0.172%	-0.771%		
Other									
actual	573	34	563	1170	371	290	24	685	1855
Facility									
goal	314003	360237	464744	1138984	517238	466670	375166	1359074	2498058
actual	335748	327277	525376	1188401	553975	402226	368506	1324707	2513108
%dev	6.925%	-9.150%	13.046%	4.339%	7.103%	-13.809%	-1.775%	-2.529%	0.602%
cum %dev	6.925%	-1.663%	4.339%		5.202%	1.023%	0.602%		
Mobility									
goal	105063	105063	105064	315190	143668	143668	143668	431004	746194
actual	95999	115602	99338	310939	126333	143296	166858	436487	747426
%dev	-8.627%	10.031%	-5.450%	-1.349%	-12.066%	-0.259%	16.141%	1.272%	0.165%
cum %dev	-8.627%	0.702%	-1.349%		-4.704%	-3.644%	0.165%		
Total									
goal	419066	465300	569808	1454174	660906	610338	518834	1790078	3244252
actual	431747	442879	624714	1499340	680308	545522	535364	1761194	3260534
%dev	3.026%	-4.819%	9.636%	3.106%	2.936%	-10.620%	3.186%	-1.614%	0.502%
cum %dev	3.026%	-1.101%	3.106%		3.053%	-0.009%	0.502%		

cum %dev = cummulative percent deviation
other = propane and fuel oil

REF NO. 7-6

AP-42
Supplement 9

SUPPLEMENT NO. 9
FOR

COMPILATION OF AIR POLLUTANT EMISSION FACTORS, THIRD EDITION (INCLUDING SUPPLEMENTS 1-7)

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

July 1979

NATIONAL EMISSION DATA SYSTEM

SOURCE CLASSIFICATION CODES AND EMISSION FACTOR LISTING

SCC	PROCESS	POUNDS EMITTED PER UNIT					UNITS
		PART	SO_x	NO_x	HC	CO	
NOTE: A. Both boiler capacities and throughputs must be reported to NEDS for all boilers. B. Most SCC codes in the 99 categories have been deleted in this listing because specific boiler codes are available. C. Unless otherwise indicated, SCC's are defined to include all boiler sizes.							
EXTERNAL COMBUSTION BOILERS - COMMERCIAL/INSTITUTIONAL							
Anthracite Coal							
1-03-001-01	Pulverized coal	17.0 A	38.0 S	18.0	0.00	1.00	Tons burned
1-03-001-02	Travelling grate (overfeed) stoker	1.00 A	38.0 S	10.0	0.00	1.00	Tons burned
1-03-001-03	Hand-fired	10.0	38.0 S	3.00	2.50	90.0	Tons burned
Bituminous Coal							
1-03-002-05	Pulverized coal: wet bottom	13.0 A	38.0 S	30.0	0.30	1.00	Tons burned
1-03-002-06	Pulverized coal: dry bottom	17.0 A	38.0 S	18.0	0.30	1.00	Tons burned
1-03-002-07	Over and underfeed stokers greater than 10 MMBtu/hr	5.00 A	38.0 S	15.0	1.00	2.00	Tons burned
1-03-002-09	Spreader stoker	13.0 A	38.0 S	15.0	1.00	2.00	Tons burned
1-03-002-11	Over and underfeed stokers less than 10 MMBtu/hr	2.00 A	38.0 S	6.00	3.00	10.0	Tons burned
Lignite							
1-03-003-05	Pulverized coal	7.00 A	30.0 S	14.0	0.30	1.00	Tons burned
1-03-003-07	Travelling Grate (overfeed) stoker	3.00 A	30.0 S	6.00	1.00	2.00	Tons burned
1-03-003-09	Spreader stoker	7.00 A	30.0 S	6.00	1.00	2.00	Tons burned
Residual Oil							
1-03-004-01	Grade 6 oil	12.0 S[1]	159.0 S	60.0	1.00	5.00	1000 gallons burned
1-03-004-04	Grade 5 oil	10.0	159.0 S	60.0	1.00	5.00	1000 gallons burned
Distillate Oil							
1-03-005-01	Grades 1 and 2 oil	2.00	144.0 S	22.0	1.00	5.00	1000 gallons burned
1-03-005-04	Grade 4 oil	7.00	150.0 S	22.0	1.00	5.00	1000 gallons burned
Natural Gas							
1-03-006-01	Over 100 MMBtu/hr	10.0	0.60	700.0	1.00	17.0	Million cubic feet burned
1-03-006-02	10-100 MMBtu/hr	10.0	0.60	180.0	3.00	17.0	Million cubic feet burned
1-03-006-03	Less than 10 MMBtu/hr	10.0	0.60	120.0	8.00	20.0	Million cubic feet burned
Process Gas							
1-03-007-01	Sewage gas						Million cubic feet burned
1-03-007-99	Other/not classified (specify fuel in comment field)						Million cubic feet burned

'A' indicates the ash content of the fuel.

'S' indicates the sulfur content of the fuel on a percent-by-weight basis.

[1]Particulate emissions from residual oil combustion can be more accurately estimated from the equation lb/1000 gal = 10S + 3. See AP-42, page 1.3-2.

REF. NO. 7-7

EPA-600/7-80-097

May 1980

Environmental Assessment: Source Test and Evaluation Report — Wellman-Galusha (Ft. Snelling) Low-Btu Gasification

by

M.P. Kilpatrick, R.A. Magee, T.E. Emmel,
and G.C. Page

Radian Corporation
P.O. Box 9948
Austin, Texas 78766

Contract No. 68-02-2147
Exhibit A
Program Element No. INE825

EPA Project Officer: William J. Rhodes

Industrial Environmental Research Laboratory
Office of Environmental Engineering and Technology
Research Triangle Park, NC 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

APPENDIX A
PROCESS MATERIAL AND ENERGY BALANCES

This appendix contains the process data characterizing the lignite gasification test run conducted by the Bureau of Mines in December of 1978. From this data, the process operation during the sampling periods was characterized and the effluent flow rates were developed.

Material and energy balance data provided by the Bureau of Mines for the lignite gasification test run conducted by the Bureau from December 11, 1978 through December 14, 1978 are presented in the following Tables A-1 through A-5. This information was developed from process data collected, stored, and calculated by the Bureau of Mines data acquisition system. Each table represents information averaged over distinct operating periods. The information contained in Tables A-1 through A-5 was used to develop most of the process data presented in Section 2.0 of this report.

Material balances presented in Tables A-6 and A-7 for carbon, hydrogen, oxygen, nitrogen, sulfur, ash, and total mass for the process streams during the two major sampling time periods were calculated from the Bureau of Mines material balances (Tables A-2, A-3, and A-4). Figure A-1 shows the relationship between the two sampling time periods and the Bureau material balance time periods. The first sampling time period 1430 to 2130 on December 12, 1978, occurred during the plant operating time period covered by Table A-2 and this table was used directly to obtain Table A-6. The second sampling time period, 1600 to 0300 on December 13 and 14, 1978 occurred during the plant operating time periods covered by Table A-3 and A-4. The data from these tables were simply averaged to obtain Table A-7. Table A-8 contains the flow rate data used in calculating Tables A-6 and A-7 as well as the calculated flow rates excluding moisture which were used in the body of this report to calculate mass flow. Gasifier ash sluice water and cyclone dust quench water rates (not part of Tables A-6 and A-7) were estimated at 0.007 ℓ/s ($\sim$7 gph) each. These estimates were made from visual observations during the test run.

The test burner flue gas rate and composition presented in Table A-9 were estimated from process and sampling data because no direct measurement was made. The product gas rate to the burner was estimated by subtracting the product gas flow rate measured to the kiln from the total product gas produced as calculated by the Bureau material balances. The natural gas rate to the burner pilot and the combustion air rates to the burner were estimated using the design flow rates for the test burner. From this data and the product gas composition measured by GC analysis taken at 2010 on December 12, 1978, the test burner flue gas rate and composition was calculated. The estimated test burner dry flue gas composition compares favorably to the GC analysis of a sample taken at 2006 on December 12, 1978. This close agreement between the estimated and measured flue gas composition supports the assumptions.

TABLE A-1. PROCESS DATA SEGMENT 1, 12-11-78

GASIFIER MASS BALANCE- AKP-29 INDIANHEAD LIGNITE 12/11(345)-21130 TO 346-01130

INPUT(LBS/HR)	C	H	O	N	S	ASH	TOTAL
COAL	1833.2	263.1	1633.2	25.6	34.2	315.9	4101.0
STEAM	.0	97.2	770.0	.0	.0	.0	866.0
DRY AIR	.8	.0	1537.2	4996.7	.0	.0	6618.0
TOTAL	1834.0	360.3	3940.5	5022.4	34.2	315.9	11585.7

OUTPUT(LBS/HR)	C	H	O	N	S	ASH	TOTAL
DRY GAS	1701.1	160.6	2488.8	4768.9	27.3	1.4	9234.9
ROT ASH	24.4	1.4	7.0	.3	5.2	309.5	347.8
CYC DUST	29.0	1.9	8.2	.4	.5	5.0	45.0
WATER	.0	184.8	1463.4	.0	.0	.0	1647.2
TAR	128.2	12.7	13.9	2.8	1.1	.0	159.0
TOTAL	1882.7	361.4	3981.3	4772.4	34.2	315.9	11434.0

OPERATING DATA

COAL ANALYSIS	
C	64.40
H	4.30
O	18.20
N	.90
S	1.20
MOISTURE	30.60
ASH	11.10
HHV	10886.
LHV	10373.

GAS ANALYSIS	
O2	.000
A	.577
CO2	9.947
H2O	19.600
CALC H2O	19.229
N2	44.789
H2S	.224
CALC H2S	.224
CH4	1.905
C2H6	.098
H2	17.208
CO	29.843
C2H4	.093
GMS TAR/DRY SCF	.500

GAS PRODUCTION	WET SCFH	DRY SCFH
MEASURED	179000.	144274.
/SQ.FT.GRATE	5394.62	4348.22
/LB RAW COAL	43.65	35.18
/LB DRY COAL	62.89	50.69
/LB MAF COAL	74.87	60.34
CALCULATED (C BALANCE)	174265.	140458.

AIR:	SCFH	RH
AMBIENT	87720.	50.00
TO GASIFIER	105045.	100.34

WATER(GPM):	
AGITATOR	3.06
TO SHELL	6.41
FROM SHELL	4.77
EVAPORATED	1.64

	LB/LB
STEAM/RAW COAL	.211
TOTAL WATER/DRY COAL	.746
AIR/RAW COAL	1.625
AIR/DRY COAL	2.341
AIR/MAF COAL	2.787
WATER REACTED/MAF COAL	.199

TABLE A-1. CONTINUED

GASIFIER HEAT BALANCE- GKP-29 INDIANHEAD LIGNITE 12/11(345)-21:30 TO 346-01:30

INPUT(BTU/HR)

	SENSIBLE	COMBUSTION	TOTAL	PCT
COAL	.134367E+05	.309829E+08	.309964E+08	99.97
AIR	.106348E+05	.000000E+00	.106348E+05	.03
TOTAL	.240715E+05	.309829E+08	.310070E+08	100.00

OUTPUT(BTU/HR)

	SENSIBLE	COMBUSTION	TOTAL	PCT
HOT ASH	.786799E+04	.395187E+06	.403055E+06	1.30
CYC DUST	.232370E+04	.465494E+06	.467818E+06	1.51
AGIT H2O	.383357E+05	.000000E+00	.383357E+05	.12
JACKET H2O	.339635E+06	.000000E+00	.339635E+06	1.10
HOT GAS (CYC OUTLET)	.912526E+06	.271573E+08	.280699E+08	90.53
HEAT LOSS	.168831E+07	.000000E+00	.168831E+07	5.44
TOTAL	.298900E+07	.280180E+08	.310070E+08	100.00

****

OPERATING DATA

INPUT	TEMP(DEG C)
COAL	19.1
AMBIENT AIR	19.1
SATURATED AIR	58.4
AGITATOR H2O	6.0
JACKET H2O	6.0

RAW GAS DATA	BTU/WET SCF	BTU/DRY SCF
AFTER CYC(60.DEG F)	151.72	188.23
AT CHAMB(140.DEG C)	156.13	193.71
AT KILN(147.DEG C)	156.39	194.02
TAR CONTRIBUTION(60 F)	13.72	17.02(15441 BTU/LB TAR)

OUTPUT	TEMP(DEG C)
HOT ASH	76.4
CYC DUST	159.0
AGITATOR H2O	19.9
JACKET H2O	85.0
GASER OUTLET	164.0
CYCLONE OUTLET	159.0
MAIN FLOW	150.0
KILN FLOW	150.0

TRANSMISSION LOSSES	BTU/HR	PCT
CYCLONE	.32294E+05	21.72
CYC-MAIN FLOW	.58046E+05	39.04
MAIN FLOW-COMB CHAMB	.55739E+05	37.49
MAIN FLOW-KILN FLOW	.31002E-01	.00
KILN FLOW-KILN	.25910E+04	1.74

TABLE A-2. PROCESS DATA SEGMENT 2, 12-12-78

GASIFIER MASS BALANCE- GKP-29 INDIANHEAD LIGNITE 12/12(346)-13:30 TO 21:00

INPUT(LBS/HR)	C	H	O	N	S	ASH	TOTAL
COAL	1144.3	166.2	1019.5	16.0.	21.3	197.2	2560.0
STEAM	.0	59.2	469.1	.0	.0	.0	528.1
DRY AIR	.5	.0	921.9	2996.7	.0	.0	3969.0
TOTAL	1144.8±	273.4	2410.6	3012.7	21.3	197.2	7057.0
	160	235	1200	420	3.0		

OUTPUT(LBS/HR)	C	H	O	N	S	ASH	TOTAL
DRY GAS	1047.8	101.3	1553.8	2963.1	17.0	1.5	5736.2
HOT ASH	15.1	.9	4.3	.2	3.2	192.4	216.2
CYC DUST 3%	19.3	1.3	5.5	.3	.4.	3.3	30.0
WATER 10%	.0	114.6	907.5	.0	.0	.0	1021.5
TAR 10%	79.5	7.9	9.6	1.8	.7	.0	98.6
TOTAL	1161.8	225.9	2479.5	2965.4	21.3	197.2	7102.5

OPERATING DATA

COAL ANALYSIS	
C	64.40
H	4.30
O	18.20
N	.90
S	1.20
MOISTURE	30.00
ASH	11.10
HHV	10886.
LHV	10373.

GAS ANALYSIS	
O2	.000
A	.553
CO2	6.203
H2O	19.400
CALC H2O	18.929
N2	44.879
H2S	.225
CALC H2S	.225
CH4	1.521
C2H6	.103
H2	17.421
CO	28.806
C2H4	.145
GMS TAR/DRY SCF	.500

GAS PRODUCTION	WET SCFH	DRY SCFH
MEASURED	111000.	89666.
/SQ.FT.GRATE	3355.39	2696.38
/LB RAW COAL	43.36	34.95
/LB DRY COAL	62.48	50.36
/LB MAF COAL	74.37	59.94
CALCULATED (C BALANCE)	109339.	88127.

AIR:	SCFH	RH
AMBIENT	52608.	50.00
TO GASIFIER	63172.	100.49

WATER(GPM):	
AGITATOR	3.45
TO SHELL	5.00
FROM SHELL	4.00
EVAPORATED	1.00

	LB/LB
STEAM/RAW COAL	.206
TOTAL WATER/DRY COAL	.738
AIR/RAW COAL	1.551
AIR/DRY COAL	2.249
AIR/MAF COAL	2.677
WATER REACTED/MAF COAL	.195

TABLE A-2. CONTINUED

GASIFIER HEAT BALANCE- GKP-24 INDIANHEAD LIGNITE 12/12(346)-13:30 TO 21:00

INPUT(BTU/HR)

	SENSIBLE	COMBUSTION	TOTAL	PCT
COAL	.957241E+04	.193407E+08	.193503E+08	99.96
AIR	.727964E+04	.000000E+00	.727964E+04	.04
TOTAL	.168520E+05	.193407E+08	.193576E+09	100.00

OUTPUT(BTU/HR)

	SENSIBLE	COMBUSTION	TOTAL	PCT
HOT ASH	.489869E+04	.245557E+06	.250556E+06	1.29
CYC DUST	.120354E+04	.310440E+06	.311533E+06	1.61
AGIT H2O	.251867E+05	.000000E+00	.251867E+05	.13
JACKET H2O	.302836E+06	.000000E+00	.302836E+06	1.56
HOT GAS (CYC OUTLET)	.438991E+06	.167033E+08	.171423E+08	88.56
HEAT LOSS	.132514E+07	.000000E+00	.132514E+07	6.85
TOTAL	.209826E+07	.172593E+08	.193576E+08	100.00

OPERATING DATA

INPUT	TEMP(DEG C)
COAL	19.6
AMBIENT AIR	19.6
SATURATED AIR	50.5
AGITATOR H2O	6.0
JACKET H2O	6.1

RAW GAS DATA	BTU/WET SCF	BTU/DRY SCF
AFTER CYC(60.DEG F)	150.48	186.70
AT CHAMB(110.DEG C)	153.83	190.85
AT KILN(112.DEG C)	153.90	190.94
TAR CONTRIBUTION(60 F)	13.72	17.02(15441 BTU/LB TAR)

OUTPUT	
BOT ASH	78.5
CYC DUST	127.0
AGITATOR H2O	14.1
JACKET H2O	90.1
GASER OUTLET	144.0
CYCLONE OUTLET	127.0
MAIN FLOW	120.0
KILN FLOW	115.0

TRANSMISSION LOSSES	BTU/HR	PCT
CYCLONE	.63477E+05	49.21
CYC-MAIN FLOW	.27878E+05	21.48
MAIN FLOW-COMB CHAMB	.31249E+05	24.07
MAIN FLOW-KILN FLOW	.42553E+04	3.28
KILN FLOW-KILN	.25510E+04	1.97

TABLE A-3. PROCESS DATA SEGMENT 3, 12-13-78

GASIFIER MASS BALANCE- BKP-29 INDIANHEAD LIGNITE 12/13(347)-10:30 TO 20:30

INPUT(LBS/HR)	C	H	O	N	S	ASH	TOTAL
COAL	840.4	120.6	748.7	11.7	15.7	144.0	1880.0
STEAM	.0	50.1	396.8	.0	.0	.0	445.6
DRY AIR	.4	.0	693.6	2254.5	.0	.0	2900.0
TOTAL	840.8	170.7	1839.1	2266.2	15.7	144.8	5312.6

OUTPUT(LBS/HR)	C	H	O	N	S	ASH	TOTAL
DRY GAS	755.2	73.0	1119.9	2135.7	12.5	1.7	4135.6
HOT ASH	11.1	.6	3.2	.2	2.4	140.9	156.3
CYC DUST	12.9	.9	3.6	.2	.2	2.2	20.0
WATER	.0	98.5	780.0	.0	.0	.0	878.0
TAR	57.3	5.7	6.2	1.3	.5	.0	71.1
TOTAL	836.5	178.7	1912.9	2137.4	15.7	144.8	5262.9

OPERATING DATA

COAL ANALYSIS	
C	64.40
H	4.30
O	18.20
N	.90
S	1.20
MOISTURE	30.60
ASH	11.10
HHV	10885.
LHV	10373.

GAS ANALYSIS	
O2	.000
A	.577
CO2	6.203
H2O	22.300
CALC H2O	19.022
N2	44.875
H2S	.230
CALC H2S	.230
CH4	1.521
C2H6	.103
H2	17.419
CO	28.803
C2H4	.145
GMS TAR/DRY SCF	.500

GAS PRODUCTION	WET SCFH	DRY SCFH
MEASURED	83000.	64491.
/SQ.FT.GRATE	2501.51	1943.67
/LB RAW COAL	44.15	34.30
/LB DRY COAL	63.62	49.43
/LB MAF COAL	75.73	58.84
CALCULATED (C BALANCE)	83629.	64824.

AIR:	SCFH	RH
AMBIENT	39482.	50.00
TO GASIFIER	48567.	100.69

WATER(GPM):	
AGITATOR	3.50
TO SHELL	6.06
FROM SHELL	5.20
EVAPORATED	.86

	LB/LB
STEAM/RAW COAL	.238
TOTAL WATER/DRY COAL	.744
AIR/RAW COAL	1.597
AIR/DRY COAL	2.301
AIR/MAF COAL	2.739
WATER REACTED/MAF COAL	.132

TABLE A-3. CONTINUED

GASIFIER HEAT BALANCE- GKP-29 INDIANHEAD LIGNITE 12/13(347)-10:30 TO 20:30

INPUT(BTU/HR)

	SENSIBLE	COMBUSTION	TOTAL	PCT
COAL	.243607E+03	.142033E+08	.142036E+08	100.00
AIR	.185649E+03	.000000E+00	.185649E+03	.00
TOTAL	.429256E+03	.142033E+08	.142038E+08	100.00

OUTPUT(BTU/HR)

	SENSIBLE	COMBUSTION	TOTAL	PCT
BOT ASH	.368367E+04	.179868E+06	.183552E+06	1.29
CYC DUST	.715960E+03	.206886E+06	.207602E+06	1.46
AGIT H2O	.340690E+05	.000000E+00	.340690E+05	.24
JACKET H2O	.419463E+06	.000000E+00	.419463E+06	2.95
HOT GAS (CYC OUTLET)	.293459E+06	.120414E+08	.123349E+08	86.84
HEAT LOSS	.102418E+07	.000000E+00	.102418E+07	7.21
TOTAL	.177557E+07	.124282E+08	.142038E+08	100.00

****

OPERATING DATA

INPUT	TEMP(DEG C)
COAL	15.7
AMBIENT AIR	15.7
SATURATED AIR	60.2
AGITATOR H2O	6.0
JACKET H2O	5.5

RAW GAS DATA	BTU/WET SCF	BTU/DRY SCF
AFTER CYC(60,DEG F)	145.09	186.72
AT CHAMB(100,DEG C)	148.08	190.57
AT KILN(115,DEG C)	148.61	191.27
TAR CONTRIBUTION(60 F)	13.23	17.02(15441 BTU/LB TAR)

OUTPUT	
BOT ASH	80.2
CYC DUST	115.0
AGITATOR H2O	16.8
JACKET H2O	95.0
GASFR OUTLET	130.0
CYCLONE OUTLET	115.0
MAIN FLOW	110.0
KILN FLOW	115.0

TRANSMISSION LOSSES	BTU/HR	PCT
CYCLONE	.44804E+05	50.08
CYC-MAIN FLOW	.14903E+05	16.66
MAIN FLOW-COMB CHAMB	.29758E+05	33.26
MAIN FLOW-KILN FLOW	-.1795E+00	-.00
KILN FLOW-KILN	.00000E+00	.00

TABLE A-4 PROCESS DATA SEGMENT 4, 12-13-78

GASIFIER MASS BALANCE- AKP-29 INDIANHEAD LIGNITE 12/13(347)-20130 TO 12/14-13130

INPUT(LBS/HR)	C	H	O	N	S	ASH	TOTAL
COAL	938.7	134.7	836.3	13.1	17.5	151.8	2100.0
STEAM	.0	66.0	529.7	.0	.0	.0	596.3
DRY AIR	.5	.0	943.7	3067.4	.0	.0	4062.6
TOTAL	939.2	201.6	2309.7	3080.5	17.5	161.8	6758.9

OUTPUT(LBS/HR)	C	H	O	N	S	ASH	TOTAL
DRY GAS	842.0	86.2	1322.7	2522.4	13.9	1.1	4802.1
ROT ASH	12.4	.7	3.5	.2	2.7	157.9	177.4
CYC DUST	16.1	1.1	6.6	.2	.3	2.8	29.0
WATER	.0	114.3	920.9	.0	.0	.0	1036.6
TAR	67.7	6.7	7.6	1.5	.5	.0	83.9
TOTAL	988.2	211.0	2259.0	2524.3	17.5	161.8	6205.0

OPERATING DATA

COAL ANALYSIS	
C	64.40
H	4.30
O	18.20
N	.90
S	1.20
MOISTURE	30.60
ASH	11.10
HHV	10646.
LHV	10373.

GAS ANALYSIS	
O2	.000
A	.665
CO2	6.204
H2O	22.300
CALC H2O	19.939
N2	44.807
H2S	.217
CALC H2S	.217
CH4	1.521
C2H6	.103
H2	17.424
CO	28.811
C2H4	.146
GMS TAR/DRY SCF	.500

GAS PRODUCTION	WET SCFH	DRY SCFH
MEASURED	94000.	76146.
/SQ.FT.GRATE	2953.59	2294.94
/LB RAW COAL	46.57	36.26
/LB DRY COAL	67.24	52.25
/LB MAF COAL	90.05	62.20
CALCULATED (C BALANCE)	93030.	72286.

AIR:	SCFH	RH
AMBIENT	53684.	50.00
TO GASIFIER	65437.	94.90

WATER(GPM):	
AGITATOR	3.50
TO SHELL	8.80
FROM SHELL	7.65
EVAPORATED	1.15

	LB/LB
STEAM/RAW COAL	.284
TOTAL WATER/DRY COAL	.850
AIR/RAW COAL	1.944
AIR/DRY COAL	2.401
AIR/MAF COAL	3.335
WATER REACTED/MAF COAL	.166

TABLE A-4. CONTINUED

GASIFIER HEAT BALANCE- GKP-29 INDIANHEAD LIGNITE 12/13(347)-20:30 TO 12/14-13:30

INPUT(BTU/HR)

	SENSIBLE	COMBUSTION	TOTAL	PCT
COAL	-.147713E+04	.159654E+08	.159640E+08	100.01
AIR	-.140288E+04	.000000E+00	-.140288E+04	-.01
TOTAL	-.288006E+04	.159654E+08	.159626E+08	100.00

OUTPUT(BTU/HR)

	SENSIBLE	COMBUSTION	TOTAL	PCT
HOT ASH	.416644E+04	.201570E+06	.205737E+06	1.30
CYC DUST	.120995E+04	.258608E+06	.259818E+06	1.64
AGIT H2O	.249208E+05	.000000E+00	.249208E+05	.16
JACKET H2O	.617095E+06	.000000E+00	.617095E+06	3.89
HOT GAS (CYC OUTLET)	.470442E+06	.142145E+08	.146850E+08	92.58
HEAT LOSS	.700226E+05	.000000E+00	.700226E+05	.44
TOTAL	.118786E+07	.146747E+08	.158626E+08	100.00

****

OPERATING DATA

INPUT	TEMP(DEG C)
COAL	14.8
AMBIENT AIR	14.8
SATURATED AIR	60.8
AGITATOR H2O	6.0
JACKET H2O	5.7

RAW GAS DATA	BTU/WET SCF	BTU/DRY SCF
AFTER CYC(50.DEG F)	145.05	186.67
AT CHAMB(120.DEG C)	148.76	191.46
AT KILN(150.DEG C)	149.85	192.85
TAR CONTRIBUTION(60 F)	13.23	17.02(15441 BTU/LB TAR)

OUTPUT	TEMP(DEG C)
HOT ASH	80.9
CYC DUST	150.0
AGITATOR H2O	13.9
JACKET H2O	95.2
GASER OUTLET	167.0
CYCLONE OUTLET	150.0
MAIN FLOW	135.0
KILN FLOW	150.0

TRANSMISSION LOSSES	BTU/HR	PCT
CYCLONE	.60647E+05	36.29
CYC-MAIN FLOW	.53154E+05	31.91
MAIN FLOW-COMB CHAMB	.52985E+05	31.81
MAIN FLOW-KILN FLOW	-.5424E+00	-.00
KILN FLOW-KILN	.00000E+00	.00

TABLE A-5. PROCESS DATA SEGMENT 5, 12-14-78

GASIFIER MASS BALANCE- AKP-29 INDIANHEAD LIGNITE 12/14(349)-16130 TO 349-00130

INPUT(LBS/HR)	C	H	O	N	S	ASH	TOTAL
COAL	1537.7	220.7	1370.0	21.5	28.7	265.0	3440.0
STEAM	.0	91.1	721.9	.0	.0	.0	812.5
DRY AIR	.7	.0	1361.8	4426.4	.0	.0	5862.6
TOTAL	1538.4	311.8	3453.6	4447.9	28.7	265.0	10115.2

OUTPUT(LBS/HR)	C	H	O	N	S	ASH	TOTAL
DRY GAS	1419.7	137.3	2105.1	4014.7	22.9	1.3	7771.0
HOT ASH	20.4	1.2	5.9	.3	4.4	259.8	291.9
CYC DUST	22.5	1.5	6.4	.3	.4	3.9	35.0
WATER	.0	185.1	1465.0	.0	.0	.0	1650.1
TAR	107.7	10.7	11.7	2.4	.9	.0	133.5
TOTAL	1570.4	335.7	3595.0	4017.7	28.7	265.0	9881.7

OPERATING DATA

COAL ANALYSIS	
C	64.40
H	4.39
O	18.20
N	.90
S	1.20
MOISTURE	30.60
ASH	11.10
HHV	10886.
LHV	10373.

GAS ANALYSIS	
O2	.000
A	.602
CO2	6.203
H2O	22.300
CALC H2O	18.536
N2	44.881
H2S	.224
CALC H2S	.224
CH4	1.521
C2H6	.103
H2	17.421
CO	28.807
C2H4	.145
GMS TAR/DRY SCF	.500

GAS PRODUCTION	WET SCFH	DRY SCFH
MEASURED	156900.	121212.
/SQ.FT.GRATE	4701.63	3653.17
/LB RAW COAL	45.35	35.24
/LB DRY COAL	65.34	50.77
/LB MAF COAL	77.79	60.44
CALCULATED (C BALANCE)	152754.	118691.

AIR:	SCFH	RH
AMBIENT	77518.	50.00
TO GASIFIER	93998.	100.85

WATER(GPM):	
AGITATOR	3.60
TO SHELL	6.41
FROM SHELL	4.85
EVAPORATED	1.56

	LB/LB
STEAM/RAW COAL	.236
TOTAL WATER/DRY COAL	.782
AIR/RAW COAL	1.713
AIR/DRY COAL	2.469
AIR/MAF COAL	2.939
WATER REACTED/MAF COAL	.108

TABLE A-5. CONTINUED

GASIFIER HEAT BALANCE- GKP-29 INDIANHEAD LIGNITE 12/14(348)-16:30 TO 349-00:30

INPUT(BTU/HR)

	SENSIBLE	COMBUSTION	TOTAL	PCT
COAL	.127359E+03	.259891E+08	.259892E+08	100.00
AIR	.988440E+02	.000000E+00	.988440E+02	.00
TOTAL	.226203E+03	.259891E+08	.259893E+08	100.00

OUTPUT(BTU/HR)

	SENSIBLE	COMBUSTION	TOTAL	PCT
HOT ASH	[illegible]	.331671E+06	.358317E+06	1.40
CYC DUST	.200892E+04	.362051E+06	.364060E+06	1.40
AGIT H2O	.151418E+05	.000000E+00	.151418E+05	.06
JACKET H2O	.377679E+06	.000000E+00	.377679E+06	1.45
HOT GAS (CYC OUTLET)	.890170E+06	.226298E+08	.235199E+08	90.50
HEAT LOSS	.137417E+07	.000000E+00	.137417E+07	5.29
TOTAL	.266583E+07	.233235E+08	.259893E+08	100.00

****

OPERATING DATA

INPUT	TEMP(DEG C)
COAL	15.6
AMBIENT AIR	15.6
SATURATED AIR	59.0
AGITATOR H2O	6.0
JACKET H2O	5.7

RAW GAS DATA	BTU/WET SCF	BTU/DRY SCF
AFTER CYC(50.DEG F)	145.05	186.70
AT CHAMB(150.DEG C)	149.86	192.87
AT KILN(175.DEG C)	150.77	194.04
TAR CONTRIBUTION(60 F)	13.23	17.02(15441 BTU/LB TAR)

OUTPUT	TEMP(DEG C)
BOT ASH	79.0
CYC DUST	175.0
AGITATOR H2O	10.8
JACKET H2O	22.1
GASER OUTLET	167.0
CYCLONE OUTLET	175.0
MAIN FLOW	165.0
KILN FLOW	175.0

TRANSMISSION LOSSES	BTU/HR	PCT
CYCLONE	.68224E+05	32.52
CYC-MAIN FLOW	.56721E+05	27.04
MAIN FLOW-COMB CHAMB	.84854E+05	40.45
MAIN FLOW-KILN FLOW	-.3636E+00	-.00
KILN FLOW-KILN	.00000E+00	.00

DAT
FILM
2-